Revised Regulatory Proposal and Interim Submission

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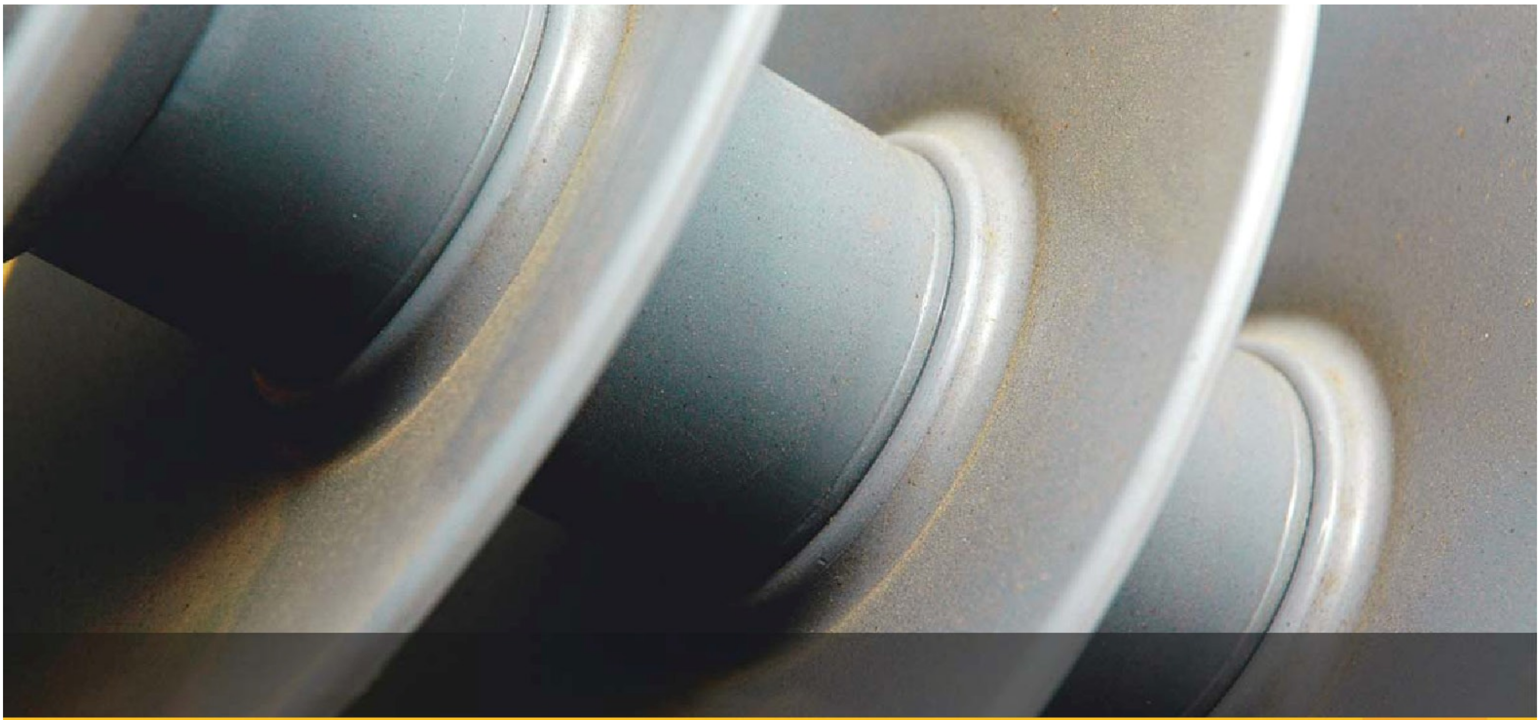

Overview and outline

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Purpose of this document

This document is EnergyAustralia's revised regulatory proposal in response to the AER's Draft Decision – NSW draft distribution determination 2009-10 to 2013-14 which was published on 28 November 2008.

This revised proposal is made under clause 6.10.3 of transitional Chapter 6 which is set out in Appendix 1 to the National Electricity Rules (the Transitional Rules).

This document also comprises an interim responding submission under clause 6.10.2 of the Transitional Rules in response to the AER's draft decision.

Structure and approach

Each chapter of this document mirrors the chapters of our June 2008 proposal. The chapters respond to the decisions the AER made with respect to our proposal and indicate in relation to each decision, whether EnergyAustralia has revised that element of its June 2008 regulatory proposal to address matters raised in the draft determination or the AER's reasons for its decision.

Where EnergyAustralia has not revised its proposal, the June 2008 proposal including the relevant attachments remains the current proposal. The elements of the proposal that have been revised are clearly indicated in this document.

EnergyAustralia has updated the information required to be submitted by Schedule 6.1 of the Transitional Rules and the Regulatory Information Notice (RIN) dated 24 April 2008 to reflect the revised proposal. This updated material is either contained in the relevant chapter of the revised proposal or in a revised RIN pro forma template or supporting document (submitted with the revised proposal) as appropriate.

Overview of this revised proposal

EnergyAustralia's revised proposal is broadly consistent with the methods and assumptions of the June 2008 proposal. We consider the underlying methodologies result in total forecasts of operating and capital expenditure that reasonably reflect prudent and efficient costs and a realistic expectation of the peak demand forecast and cost inputs required to achieve the operating and capital expenditure objectives.

EnergyAustralia's revised proposal has been prepared to address specific matters raised by the AER's draft determination. In doing so, the revised proposal takes account of significant changes which have occurred since the June 2008 proposal was prepared, in particular the announcement of an Australian Carbon Pollution Reduction Scheme (CPRS) and the impacts of the global financial crisis, particularly on economic growth and on investor behaviour.

These matters have been taken into account to the extent allowed by the Rules. As a result, EnergyAustralia has made two major revisions to its proposal:

- A revision of energy forecasts and the control mechanism; and
- A revision of the agreed period to observe market data used to set the rate of return.

These two major revisions and the changes to other parts of the framework that have been made as a consequence are discussed below.

Updated energy forecast

The AER rejected EnergyAustralia's energy forecast on the basis that it was outdated. This issue of outdated information arises from EnergyAustralia's obligation under the Rules to submit a regulatory proposal 13 months prior to the commencement of the regulatory period. EnergyAustralia has addressed the need for updated forecasts by revising its energy forecast.

EnergyAustralia considers that in revising its forecast, it is necessary to take account of all relevant information that has become available since the previous forecast was compiled. It would not be prudent, nor represent a sound forecasting methodology, to update some inputs used in the forecast with new information and disregard new information for other energy inputs. Such a methodology would not result in a realistic or consistent expectation of the demand forecast.

With consistency and currency of information as the guiding principles, EnergyAustralia has identified several factors that were not known at the time the June 2008 proposal was prepared which will impact electricity prices and consequently expected demand for energy during the 2009-14 period.

The two most significant factors impacting the forecast are the introduction of the CPRS by the Federal Government in 2010 and the change in forecasts for economic growth as a result of the global financial crisis.

The Garnaut Report released in July 2008, Commonwealth Treasury modelling, and the Government's White Paper published in December 2008 indicate that a CPRS will significantly increase electricity prices and lead to reduced energy use.

EnergyAustralia is exposed with regard to revenue recovery if actual energy volumes do not meet forecast levels. The National Electricity Law (NEL) pricing principles require that the AER to decide on forecasts that allow the opportunity for EnergyAustralia to recover at least its efficient costs.

EnergyAustralia's revised forecasts of energy rely on published information about the effects of the CPRS on energy prices and customers' sensitivity to changes in price. This is the only option available to us under the current regulatory framework.

This creates a dilemma for both the AER and EnergyAustralia:

- The CPRS will have an effect on forecast volumes, but the magnitude of this effect is uncertain.
- The AER's determination may be adjusted during the period for costs of a new regulatory obligation. However there is no provision to adjust forecast volumes during the period.
- Under the current regulatory framework, the AER must determine energy forecasts that allow EnergyAustralia the opportunity to recover its efficient costs.

The likely impact of an emissions trading scheme on electricity prices and demand for energy is a matter raised by McLennan Magasanik Associates (MMA), the consultant engaged by the AER to review the maximum demand, customer numbers and energy forecast methodologies used by EnergyAustralia for the 2009-14 forecasts.

In its report of 26 September 2008, MMA found that introduction of a carbon trading scheme or similar would impact on EnergyAustralia's energy volumes through customers' decisions to consume less electricity in response to higher prices for carbon based generation.

The AER confirmed MMA's analysis as being sound and relied on MMA's findings and recommendations regarding EnergyAustralia's maximum demand, energy and customer number forecasts to inform their decisions on X-factors and the total capital expenditure requirement for EnergyAustralia.

Stakeholders raised concerns about the impact of policies around climate change at the AER's Public Forum held on 9 December 2008.

To partly account for the uncertainty in energy volumes, and to ensure that the revenue outcomes for EnergyAustralia are consistent with the National Electricity Objective and the NEL pricing principles, EnergyAustralia has revised its proposal relating to the application of the control mechanism for standard control (DUoS) services. EnergyAustralia proposes to incorporate a 'growth factor' adjustment that acts symmetrically to protect revenues from falling (or rising) as a result of significant fluctuations in actual energy volumes compared to forecast.

This mechanism acts as insurance for both EnergyAustralia and its customers if actual revenues are too low, or too high, as a result of forecast inaccuracy in this uncertain environment. However the mechanism is a second best solution to the AER providing some alternative mechanism to reopen its determination for volumes during the period.

The global economic climate is also highly uncertain and contributes to the overall uncertainty faced by EnergyAustralia in its forecast of energy and peak demand. Economic growth has a direct impact on energy use and peak demand as businesses reduce output as a result of the economic slowdown. Similarly, fears of unemployment in the residential sector is expected to lead to falls in discretionary energy use which will place further downward pressure on energy volumes and to a lesser extent, peak demand.

EnergyAustralia has updated its energy forecast to account for CPRS and other factors influencing energy prices as well as new economic growth forecasts. In addition, EnergyAustralia has made consequential updates to the peak demand forecast to ensure there is consistency with the information underlying both the energy and peak demand forecasts. This ensures EnergyAustralia maintains a realistic expectation of the demand forecast to achieve the capital and operating expenditure objectives.

Overview and outline (continued)

EnergyAustralia has made the following revisions to its regulatory proposal to take account of the most up to date information on energy and peak demand forecasts:

- Revised X-factors to incorporate the most up to date energy forecasts;
- Revised forecasts of required capital and operating expenditures to incorporate the most up to date peak demand forecasts; and
- Revisions to the control mechanism for DUoS services to provide revenue protection in the event that actual energy volumes vary significantly from the level assumed by the updated energy forecasts.

These revisions have been incorporated into the calculation of revised building block revenues and prices.

Averaging period to determine the risk free rate and debt risk premium

The second key matter being addressed by the revised proposal is the matter raised in the AER's determination regarding the AER's decision not to agree to EnergyAustralia's proposed averaging period for determining the risk free rate parameter in the rate of return.

The AER rejected EnergyAustralia's proposed period on the basis that it considered the period was too far removed from the start of the regulatory control period. The AER's draft determination was that, consistent with past regulatory practice and CAPM theory, a period closer to the final determination date should be used as the relevant observation period for market data used in the WACC calculation.

We provide evidence to demonstrate why, in our opinion, the AER was wrong to withhold agreement on our proposed averaging period. Nevertheless we revise our proposal so the averaging period better reflects an unbiased estimate of the rate of return required by investors.

The emergence of unstable and volatile markets that characterise the global financial crisis which has occurred since the AER's decision not to accept the proposed period has important implications for the AER's specified period. The most up to date information strongly indicates that a measurement period for the risk free rate that is impacted by the current financial conditions cannot be relied on for setting a rate of return. The AER's specified agreed period is likely to include market observations set during this time of financial crisis. Expert financial evidence demonstrates that this will lead to a rate of return that is materially biased below the rate of return required by investors in a similar commercial business. Such an outcome would be contrary to the Rules and Law.

To address the AER's reasons for refusing to agree to EnergyAustralia's agreed period, EnergyAustralia has revised its agreed period. The revised period is a period closer to the beginning of the regulatory control period but which excludes market observations that are subject to abnormal financial market conditions and may result in the calculation of a downward biased estimate of the rate of return required by investors of a similar commercial entity.

Consequential and other revisions

In addition to the two major revisions discussed above, EnergyAustralia has made other revisions to its proposal to address matters raised by the AER's determination. These include revisions to:

- the forecast required capital and operating expenditure to reflect most up to date information on real cost escalators from changes in the economic climate;
- the regulatory asset base at the commencement of the next regulatory period to reflect actual FY08 capital expenditure and the most up to date information on actual CPI;
- elements of the regulatory proposal to accept certain findings of the AER;
- equity raising costs to reflect the AER's preferred treatment of these costs and to reflect revised cash flows; and
- elements of the regulatory proposal to address modelling anomalies identified by the AER or EnergyAustralia.

Addressing the specific matters raised by the AER's draft determination has given rise to a need to also revise other aspects of the June 2008 proposal to reflect consequential revisions. These consequential revisions include:

- depreciation schedules;
- debt raising costs;

- corporate income tax;
- annual revenue requirement;
- X-factors; and
- division of revenue between transmission and distribution.

It should be noted that EnergyAustralia's revised proposal utilises the methodologies upon which its June 2008 proposal was based. Where there are exceptions to this, EnergyAustralia has clearly marked these in this document.

Submissions responding to matters raised under the decision making framework

In addition to revising our proposal, each chapter of this document comprises an interim submission under clause 6.10.2 of the Transitional Rules in response to the AER's draft determination. Each chapter identifies particular areas in which EnergyAustralia either agrees or disagrees with the reasons and conclusions of the AER.

Our response to matters raised by the AER includes identifying instances where the AER's application of the decision framework has led to an incorrect outcome or decision.

There are a number of common elements to EnergyAustralia's submission responding to the AER's draft determination. In particular, we submit that, for many decisions, the AER's draft determination fails to comply fully or adequately with the obligations imposed upon the AER by the decision making framework in the Rules. We have particular concerns with the AER's approach to the consideration of our regulatory proposal.

EnergyAustralia compiled a detailed and fully substantiated regulatory proposal that complied with each of the elements of the Transitional Rules and the specific requirements of the AER's Regulatory Information Notices and Schedule 6 of the Transitional Rules.

There are instances where the AER has demonstrated due consideration of our proposal and the AER has accepted our approach or methodology. However, most AER constituent decisions reject or refuse to accept what EnergyAustralia originally proposed.

In some instances, the AER's decision to reject and substitute elements of EnergyAustralia's proposal has been supported by considered reasoning consistent with the decision making framework. In these cases, EnergyAustralia has either revised its proposal or noted the AER's decision without further justification of our June 2008 proposal.

However, for a number of its constituent decisions, it is apparent that the AER has not considered the detail of the proposal or the substantiation of the proposal. There are times when the AER has not considered the proposal at all and formulated its own decision on a relevant constituent decision without regard to EnergyAustralia's regulatory proposal and submissions.

At other times, the AER has failed to have regard to the material submitted as part of EnergyAustralia's regulatory proposal including its response to its Regulatory Information Notice and in compliance with Schedule 6.

The AER has also used consultant recommendations inconsistently. EnergyAustralia supports the use of consultants to inform the AER to enable it to make its decisions under the Rules, particularly where technical expertise is required. The AER's draft determination shows evidence where independent expertise has been utilised appropriately. However, for some constituent decisions it is apparent that the AER has sought the advice of consultants and disregarded their advice when forming their conclusion.

There are still further occasions where the AER has delegated the entire task of assessing elements of EnergyAustralia's proposal to a consultant and then adopted their recommendations, without considering that consultant's analysis against the material submitted by EnergyAustralia and in the context of the decision making process under the Rules. In some cases, the consultant itself has failed to analyse the material submitted by EnergyAustralia, and has simply expressed conclusions based on their own opinions.

This approach does not accord with the AER's obligations under the Rules. The AER is required to consider the proposal and to make constituent decisions. Further, the AER is required to provide reasons in relation to each constituent decision. Those reasons require that the methods, values and assumptions relied on and reasons are set out. If the AER has not considered the proposal or has relied on a consultant who has not considered the proposal, it simply cannot meet its obligations under the Transitional Rules.

EnergyAustralia considers that the AER has not met its obligations under the Transitional Rules in relation to its assessment of the capital and operating expenditure forecasts.

In its June 2008 proposal, EnergyAustralia submitted total forecast operating and capital expenditure in compliance with clauses 6.5.6 (forecast operating expenditure) and 6.5.7 (forecast capital expenditure) of the Rules. The methodology used by EnergyAustralia to forecast operating and capital expenditure, and the assumptions made as part of the forecasting process, are fully specified in its proposal in compliance with schedule 6.1 of the Rules. In addition, EnergyAustralia submitted detailed supporting information in relation to its operating and capital expenditure forecasts in compliance with the detailed Regulatory Information Notice dated 24 April 2008.

The AER is required to consider the submitted forecasts and the evidence and supporting material submitted by EnergyAustralia in substantiation of these forecasts. Pursuant to clauses 6.5.6(c) and 6.5.7(c), the AER must accept the forecasts if it is satisfied that the total of the forecast operating or capital expenditure for the regulatory control period reasonably reflects the operating or capital expenditure criteria, as relevant.

In determining whether it is or is not reasonably satisfied, the AER must properly consider all relevant material before it. It is not open to the AER to fail to properly consider relevant elements of the forecast operating or capital expenditure and conclude that it is not satisfied that the forecasts properly reflect the requirements of the Rules.

If the AER is not satisfied that the total forecast operating or capital expenditure amounts properly reflect the requirements of the Rules, the AER is required to set out:

- its reasons for that decision; and
- an estimate of the total of the DNSP's required operating or capital expenditure, as relevant, for the regulatory control period that the AER is satisfied reasonably reflects the operating or capital expenditure criteria, taking into account the operating or capital expenditure factors.

If the AER refuses to approve an operating or capital expenditure forecast, the substitute amount, value or methodology on which the distribution determination is based must be:

- determined on the basis of the current regulatory proposal; and
- amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

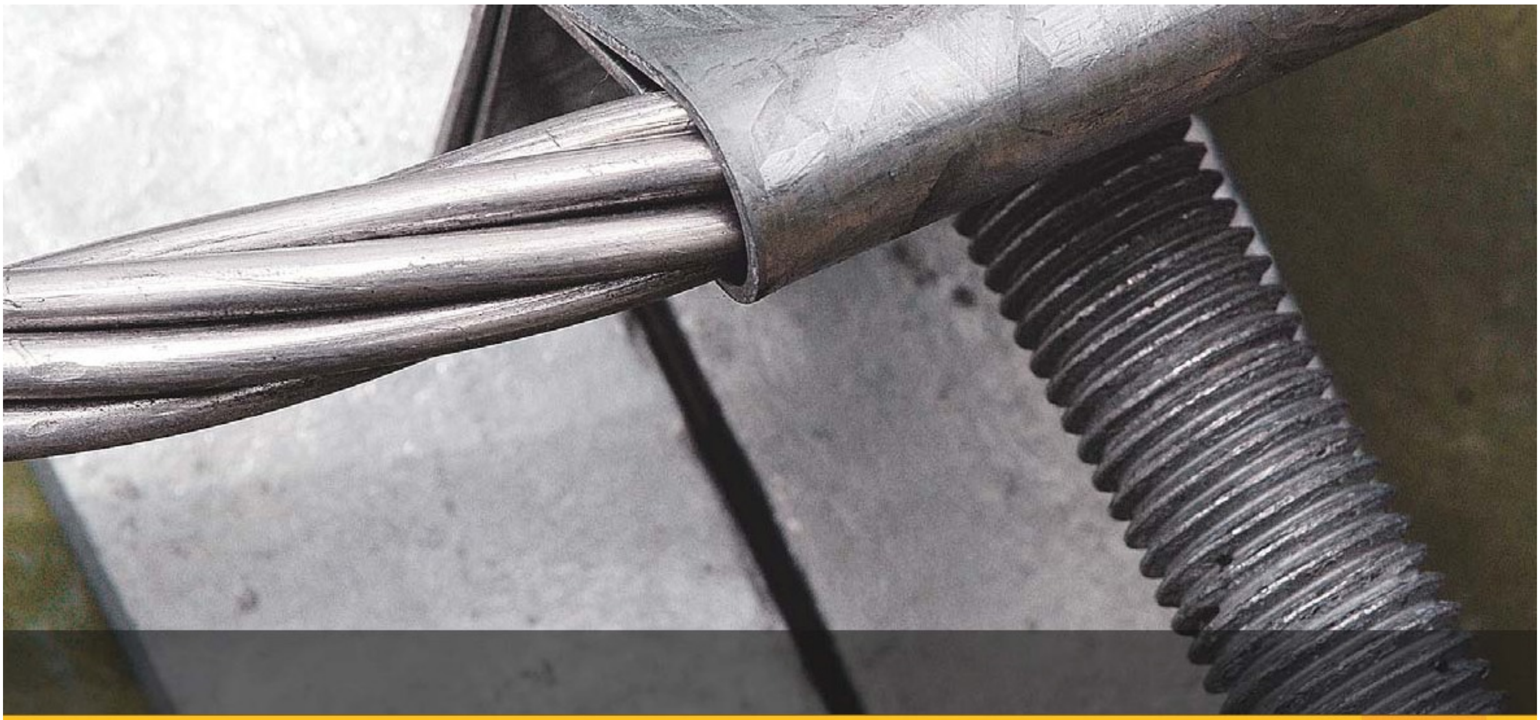
The above requires that the AER identify the particular elements of the operating and capital expenditure forecasts that it does not consider meet the relevant rule requirements, set out its reasons why it does not consider that the total forecast reasonably reflects the criteria, and then amend only to the extent necessary to enable approval.

It is clear from the provisions of the Rules that the AER is itself required to consider the detail of EnergyAustralia's proposal. It is important that the AER properly assess and test its own consultant's material and weigh that material against the material submitted by the DNSP. The AER cannot simply accept its consultant's opinion without properly testing it. Further, the AER cannot decide that it is not satisfied in relation to a capital or operating expenditure element on the basis of a perceived limitation in the evidence provided in support of that element, and then simply accept the opinion of a consultant to support a substitute amount which has no evidentiary support.

The AER should ensure that the consultants' reports sufficiently set out the reasoning and assumptions to enable the conclusions in the reports to be properly tested. The consultant should also address the right questions.

Nor can, or should, the AER simply rely on external consultant opinion as to the estimate of a building block proposal element, such as forecast operating expenditure, in rejecting a DNSP proposal. The AER is required to consider the DNSP's proposal.

We have throughout this document endeavoured to identify where the AER has not properly considered EnergyAustralia's regulatory proposal. In considering EnergyAustralia's revised regulatory proposal, it is imperative that the AER now properly consider the proposal and the material provided in its support.



Part 1 – Building block proposal

1. Annual revenue requirement

REVISED PROPOSAL

EnergyAustralia has revised its annual revenue requirement for each year of the regulatory control period and the total revenue requirement.

The Rules require that the annual revenue requirement for a Distribution Network Service Provider (DNSP) for each year of a regulatory control period must be determined using a building block approach, under which the building blocks are[1]:

- indexation of the regulatory asset base (RAB);
- a return on capital for that year;
- the depreciation for that year;
- the estimated cost of corporate income tax; and
- the revenue increments or decrements (if any) for that year (including those arising from the application of incentive schemes); and
- the forecast operating expenditure for that year.

Consequently, any revisions to one or more of the above building blocks (or inputs into one or more of those building blocks[2]) would result in revision to the annual revenue requirement and total revenue requirement.

EnergyAustralia's revised annual revenue requirement and total revenue requirement therefore reflect revisions that have been made to the following building blocks (or inputs into those building blocks) to address the matters raised by the AER's draft determination:

- indexation of the regulatory asset base;
- return on capital;
- regulatory depreciation;
- estimated cost of income tax; and
- forecast operating expenditure.

The revised annual revenue requirement and total revenue requirement have been calculated in accordance with EnergyAustralia's revised post tax revenue model (PTRM). This model is at attachment 1A.

This chapter is now substituted for Chapter 1 of Part I and Chapter 6 of Part II of the June 2008 proposal. This chapter together with Attachment 1.3 to the June 2008 proposal is now EnergyAustralia's current proposal in relation to the Annual Revenue Requirement.

Rule requirements

The AER's distribution determination is predicated on a decision to approve or refuse to approve EnergyAustralia's annual revenue requirement for each regulatory year of the regulatory control period (Clause 6.12.1(2))

The AER must approve EnergyAustralia's total revenue requirement and the annual revenue requirement if it is satisfied that these amounts have been properly calculated using the post tax revenue model on the basis of amounts calculated, determined or forecast in accordance with the requirements of Part C of the Transitional Chapter 6.

The AER must divide the revenue calculated under Part C into portions for transmission and distribution.

Our June 2008 building block proposal

EnergyAustralia proposed an annual revenue requirement for each year of the 2009-14 regulatory control period totalling $10.01 billion (nominal). This was calculated in accordance with the PTRM based on amounts calculated, determined or forecast in accordance with Part C of the Rules.

For the purpose of indexing the RAB, EnergyAustralia proposed a methodology for determining the best estimate of inflation. This methodology was based on analysis and information provided by Competition Economists Group (CEG) (Attachment 1.3 to the June 2008 proposal) and resulted in an inflation estimate of 2.54% which was used to index the RAB.

AER's draft determination

The AER:

1 Clause 6.4.3 of the Transitional Rules sets out how the annual revenue requirement for a DNSP must be determined.

2 For example, revised forecast capital expenditure is an input into the calculation of deprecation.

- refused to approve the annual revenue requirement for distribution proposed by EnergyAustralia;
- refused to approve the annual revenue requirement for transmission proposed by EnergyAustralia;
- rejected EnergyAustralia's proposed methodology for determining the best estimate of inflation;
- decided EnergyAustralia's distribution annual revenue requirement for each year of the next regulatory period totalling $8,453 million (nominal);
- decided EnergyAustralia's transmission annual revenue requirement for each year of the next regulatory period totalling $994 million (nominal); and
- determined that its current method of estimating inflation remains appropriate. This method is based on the average of the RBA's short term inflation forecast and the mid-point of the RBA's target inflation band for a ten (10) years period.

The AER's decision on EnergyAustralia's annual revenue requirement for each year of the next regulatory period resulted from its decisions on the building blocks inputs into the PTRM. These inputs include:

- a modified opening RAB as at 1 July 2009. This is further discussed in chapter 2;
- a modified rate of return. This is discussed further in chapter 8;
- substituted depreciation schedules. This is discussed further in chapter 7;
- substituted estimates of corporate income tax. This is discussed further in chapter 12;
- substituted operating expenditure forecasts. This is discussed in chapters 9-11; and
- substituted capital expenditure forecasts. This is discussed in chapters 3-6.

Our response to the AER's draft determination

EnergyAustralia has revised its annual and total revenue requirement. This revision resulted from our response to the AER's draft decisions on the building blocks or inputs into the building blocks. The revised annual and total revenue requirements are shown in table 1.1 of section 1.2 below.

EnergyAustralia notes that the AER has made two separate decisions on the annual revenue requirement, one for distribution and one for transmission.

EnergyAustralia considers that two separate and distinct decisions are required by the AER under the Rules; a decision on the annual revenue requirement for standard control services and a decision that apportions this annual revenue requirement into distribution and transmission revenues. This is further discussed in section 1.1 below.

EnergyAustralia has not revised its proposed methodology for determining the best estimate of inflation as detailed in attachment 1.3 of its June 2008 proposal. EnergyAustralia, however, has applied an inflation estimate of 2.55% determined by the AER in its draft decision in the revised post tax revenue model.

1.1 Division of EnergyAustralia's annual revenue requirement

Clause 6.3.2 of the Rules requires the AER to specify the annual revenue requirement for standard control services for each regulatory year of the regulatory control period.

Clause 6.12.1A requires the AER to divide the revenue calculated for EnergyAustralia into the following two portions:

- a portion relevant to EnergyAustralia's Prescribed (Transmission) Standard Control Services; and
- a portion relevant to other Standard Control Services provided by EnergyAustralia (i.e. distribution).

This division of revenue is to be based on EnergyAustralia's approved cost allocation method.

In its draft decision, the AER made two separate decisions:

- a decision on the annual revenue requirement for distribution and
- a decision on the annual revenue requirement for transmission.

By making two separate decisions on the annual revenue requirement, one for distribution and one for transmission, the

AER implicitly divided EnergyAustralia's revenue calculated under Part C of the Rules into two relevant portions; and presumably, these two revenue portions would, together, constitute EnergyAustralia's annual revenue requirement for standard control services.

Therefore, it does not appear that the AER has made both:

- a decision on EnergyAustralia's annual revenue requirement for standard control services and
- a decision which divides the EnergyAustralia's annual revenue requirement into two portions, one for distribution and one for transmission.

EnergyAustralia acknowledges that this is a minor technical issue. However, separating the decisions relating to the calculation of the revenue requirement and the division of the revenue requirement would appear more consistent with the regulatory framework.

1.2 EnergyAustralia's revised annual revenue requirement

The table below shows the building blocks of EnergyAustralia's revised annual revenue requirement. Each building block is further discussed below.

Table 1.1 EnergyAustralia's revised annual revenue requirement ($ million, nominal)

	FY10	FY11	FY12	FY13	FY14
Return on capital	853	1032	1195	1378	1562
Regulatory depreciation	75	101	125	150	145
Tax allowance	43	45	89	101	107
Operating expenditure	577	612	646	685	714
Annual revenue requirement	1548	1790	2055	2314	2528

Indexation of the asset base

In making a building block determination, the AER is required to determine an appropriate method for indexing the RAB. That method must be a method that is likely to result in the best estimate of inflation.

The AER has not accepted the method proposed by EnergyAustralia for determining the best estimate of inflation. The AER decided that its preferred method, based on the average of the RBA's short term forecast and mid point of the target inflation band, remains appropriate. Using this method, the AER determined that an inflation forecast of 2.55%, is the best estimate for a 10 year period and applied this forecast in the PTRM for its draft decision.

EnergyAustralia still considers the method proposed in the June 2008 regulatory proposal[3] remains a more appropriate method for determining the best estimate of inflation. This is because:

- this method draws on forecasts of a range of professional forecasters instead of relying on the sole forecasts and inflation target band produced by the RBA; and
- there is an inherent risk of forecasting error in relying on the observation of one forecaster only. This risk is reduced in using a wide range of forecasts; and therefore likely to result in a more robust estimate of inflation.

Nevertheless, EnergyAustralia has applied an inflation input of 2.55% consistent with the AER's draft determination, noting the AER's decision and its intention to update this forecast closer to the final determination. EnergyAustralia would ask that the AER considers the method proposed in our June 2008 proposal when making its final determination.

Table 1.2 shows EnergyAustralia's revised RAB during the 2009-14 regulatory control period. These values reflect:

- EnergyAustralia's revised opening RAB (chapter 2).
- EnergyAustralia's revised forecast capital expenditure (chapters 3-6).

[3] Attachment 1.3 to the June 2008 proposal

- An inflation input of 2.55% as determined by the AER in its draft determination, noting that this input will be updated closer to the final determination.

Table 1.2 EnergyAustralia's revised opening RAB ($ billion, nominal)

	FY10	FY11	FY12	FY13	FY14
Opening RAB (as at 1 July)	8.40	10.16	11.77	13.57	15.39

Return on capital for the year

The Rules stipulate that the return on capital for each regulatory year must be calculated by applying a rate of return to the value of the opening RAB for that regulatory year[4].

Table 1.3 shows EnergyAustralia's revised return on capital building block. These revised values reflect:

- revised rate of return of 10.15% (chapter 8) and
- revised opening RAB value for each year as shown in table 1.2 above.

Table 1.3 EnergyAustralia's revised return on capital ($ million, nominal)

	FY10	FY11	FY12	FY13	FY14
Return on capital	853	1032	1195	1378	1562

Depreciation for the year

As discussed in chapter 7 of our response, EnergyAustralia has revised its depreciation building block in response to the AER's draft decision. Table 1.4 below shows the revised revenue allowance for the depreciation building block.

Table 1.4 EnergyAustralia's revised depreciation building block ($ million, nominal)

	FY10	FY11	FY12	FY13	FY14
Nominal depreciation	289	360	425	496	537
Less: inflation on RAB	214	259	300	346	392
Depreciation building block	75	101	125	150	145

Estimated cost of income tax for the year

EnergyAustralia has revised its estimated cost of income tax for each year of the 2009-14 regulatory control period to address matters raised by the AER's draft determination. This is further discussed in chapter 12 of this response.

Table 1.5 below shows the revised cost of income tax building block.

Table 1.5 EnergyAustralia's revised cost of corporate income tax ($ million, nominal)

	FY10	FY11	FY12	FY13	FY14
Estimated cost of income tax	43	45	89	101	107

[4] Clause 6.5.2(a) of the Transitional Rules.

2. Regulatory asset base

REVISED PROPOSAL

EnergyAustralia has revised its June 2008 proposal for the nominal opening value of the RAB for the 2009-14 regulatory control period.

In its draft decision, the AER noted that it will update the roll forward of EnergyAustralia's RAB at a time closer to its final determination, with:[5]

- actual capital expenditure for 2008 FY;
- the most recent forecast of capital expenditure for 2009 FY; and
- latest available CPI data.

The AER also raised the following issues with respect to the RAB by EnergyAustralia in its June 2008 proposal:[6]

- the real pre –tax and nominal vanilla WACC values.
- the methods used to calculate actual inflation.

In responding to matters raised by the AER in its draft determination, EnergyAustralia has revised the opening RAB from its June 2008 proposal in the following manner:

- Replace the estimate of net capital expenditure used in the June 2008 proposal for the 2008 FY with the actual value. This value was not available at the time of submitting the June 2008 proposal.
- Replace the estimate of inflation used in the June 2008 proposal for the 2008 FY with actual inflation.
- Update the estimate of inflation for the 2009 FY with the latest available CPI data.
- Incorporate into the roll forward of the Distribution opening RAB the real pre-tax WACC for 2004 FY as decided by the AER.
- Incorporate into the roll forward of the transmission opening RAB the nominal vanilla WACC for the current regulatory control period as decided by the AER.

Additionally, the update of inflation inputs for the 2008 FY and 2009 FY have a consequential impact on the value of assets transferred from distribution to transmission. This updated value is shown in tables 2.1 and 2.2 below.

EnergyAustralia has not revised its opening RAB to reflect all the matters raised by the AER in its draft determination. EnergyAustralia has made no changes to the method and approach to establishing the RAB in its June 2008 proposal.

EnergyAustralia notes in this chapter the reasons why not all the matters raised by the AER have resulted in changes to the revised opening RAB.

Details of amounts, inputs and values used by EnergyAustralia in the calculation of the opening RAB value are shown in the attached Roll Forward Model (RFM) (Attachment 2A) and supporting files.

This chapter now substitutes for Chapter 2 of the June 2008 proposal except for section 2.2.1 of that proposal. The matter addressed at section 2.3 and Table 2.1 of that proposal are now addressed in Chapter 1 of this revised proposal. Section 2.2.1 and Attachment 2.1 to the June 2008 proposal should be considered in conjunction with this chapter.

Rule requirements

The AER's draft determination is predicated on a decision on the regulatory asset base as at the commencement of the regulatory control period in accordance with clause 6.5.1 and schedule 6.2 of the Transitional Rules.(Clause 6.12.1(6)).

Our June 2008 building block proposal

EnergyAustralia proposed an opening RAB of $8,218 million as at 1 July 2009. This comprised of $7,229 million for Distribution and $989 million for transmission.

AER's draft determination

The AER decided that the opening asset base for distribution is $7,203 million and for transmission is $985 million.

[5] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p80

[6] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p64 and p74.

The AER was satisfied that EnergyAustralia had completed the RFM with inputs that are in accordance the transitional rules except for the:

- real pre-tax WACC input used in the calculation of the opening RAB for distribution. The AER amended this input from 7% to 7.5%;
- nominal vanilla WACC for the current regulatory control period used in the calculation of the opening RAB for transmission. The AER amended this input from 8.92% to 9.08%; and
- methods used to calculate the actual inflation inputs into both the distribution and transmission RFM. The AER recalculated these inflation inputs and incorporated them into the opening RAB values that it has decided.

Our response to the AER's draft determination

EnergyAustralia accepts the AER's decision to amend the opening RAB for:

- the real pre-tax WACC applicable to distribution for the 2004 FY of 7.5%. This value was approved by IPART.
- the nominal vanilla WACC for the current regulatory control period for transmission of 9.08%. This value was determined by the AER following its revocation and substitution of EnergyAustralia's revenue cap in December 2007.

EnergyAustralia, however, does not accept the AER's findings that the methods used to calculate actual inflation in its June 2008 proposal are inconsistent with the requirements of the National Electricity Rules.

Section 2.1 below demonstrates how our methods for calculating actual inflation are in accordance with the requirements of the National Electricity Rules.

Section 2.2 explains how the revised inflation estimates have been applied to calculate the revised RAB and reconciles that calculation to the June 2008 proposal.

2.1 Indexation of the regulatory asset base

In its draft decision, the AER stated that:

- the method used by EnergyAustralia to calculate actual inflation inputs to the roll forward model for adjusting the opening distribution RAB is not consistent with that approved by IPART[7]; and
- the method used by EnergyAustralia to calculate actual inflation inputs to the roll forward model for adjusting the transmission opening RAB is not consistent with that used for indexation of the maximum allowed revenue.[8]

Accordingly, the AER recalculated the actual inflation inputs used in the roll forward model for calculating the distribution and transmission opening RAB.

EnergyAustralia's comments

Rules requirements

EnergyAustralia does not agree with the AER's findings. Our methods to calculate actual inflation are in accordance with the requirements of the Rules and did not require amendment.

Clause 6.5.1(e)(3) requires that the opening RAB values are to be adjusted for "actual inflation, consistently with the method used for the indexation of the control mechanism (or control mechanisms) for standard control services during the preceding regulatory control period".

Clause 6.5.1(h) requires the RFM for EnergyAustralia's transmission network assets to be applied as if the AER were separately regulating EnergyAustralia's transmission system under the relevant provisions of chapter 6A.

Clause 6A.6.1(e)(3) of chapter 6A requires that the opening value of transmission assets is to be adjusted for "outturn inflation, consistent with the methodology that was used in

[7] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p64.
[8] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p74.

the transmission determination.. for the indexation of the maximum allowed revenue…".

To establish the opening RAB in 2009, the Rules therefore require the two RABs to be rolled forward using two different indexation methods. The Rules establish a single RAB roll forward position for all of EnergyAustralia's network assets in the next regulatory control period (i.e. at 2009).

Indexation methods

EnergyAustralia has applied the following indexation methods to calculate the inflation used to adjust the opening RAB values.

Distribution: the sum of four quarters method for calculating the annual change in CPI.

Transmission: the year on year method for calculating the annual change in CPI.

The above methods were used by IPART and the ACCC in establishing the control mechanisms for distribution and transmission for the 2004-09 regulatory control period.

EnergyAustralia notes that in its draft decision, the AER has used the same indexation methods as described above to calculate the actual inflation inputs.

Application of the indexation methods

In applying the above methods, the AER did not use the "actual" inflation that occurred over the financial years over which the asset value was being rolled forward. Instead it used a lagged approach. The AER used the following approach:

- for distribution, the sum of four quarters to December CPI. For example, the AER used the change in the sum of four quarters to December 2006 CPI to the sum of four quarters to December 2005 CPI as the actual inflation input for the 2007 FY.
- for transmission, the March on March CPI. For example, the AER used the change in the March 2007 quarter CPI to the March 2006 quarter CPI as the actual inflation input for 2007 FY.

This is different to what EnergyAustralia proposed.

EnergyAustralia used actual CPI data for each financial year to calculate the applicable actual inflation required to adjust the opening RAB. That is:

- to adjust the distribution RAB, EnergyAustralia used the change in the sum of four quarters to June CPI. For example, EnergyAustralia calculated the actual inflation for 2007 FY as the change in the sum of four quarters to June 2007 to the sum of four quarters to June 2006; and
- to adjust the transmission RAB, EnergyAustralia used the change in the June quarter CPI. For example, EnergyAustralia calculated the actual inflation for 2007 FY as the change in June 2007 quarter CPI to June 2006 quarter CPI.

Conclusion

EnergyAustralia considers that the methods that it has used are consistent with those applied in previous determinations.

Clause 6.5.1(e)(3) of the Rules requires the opening RAB to be adjusted for actual inflation. To calculate the actual inflation for a particular financial year, EnergyAustralia considers it appropriate to apply the actual CPI data for that financial year to the respective indexation methods; with those methods being consistent with the methods used for the indexation of the control mechanisms.

EnergyAustralia has therefore not changed its June 2008 proposal with respect to the methods for calculating actual inflation and considers that the AER should consider its decision in light of the above evidence.

2.2 EnergyAustralia's revised opening RAB

A single opening RAB value

The AER, in its draft decision, appears to have made two decisions on the opening RAB, one for transmission and one for distribution. This gives the impression that for the 2009-14 period, the roll forward of two separate RABs is required whereas only one roll forward of the RAB is necessary. This is a minor technical issue but we see some benefit in clarifying for stakeholders that the AER makes a decision on a single opening RAB for the regulatory control period.

Revised inflation estimates

The indexation methods described above are used to calculate the inflation estimates for 2009 FY based on the most up to date CPI data. At the time of the June 2008 proposal, the most current CPI observation was the March 2008 quarter; and this was used to calculate the inflation estimates for the 2008 FY and 2009 FY. These estimates were incorporated into the opening RAB values submitted in the June 2008 proposal.

Where actual CPI data for a financial year is not available, EnergyAustralia uses the latest available actual CPI and applies it to the respective indexation methods to calculate an estimate of actual inflation for that financial year.

The most current actual CPI at the time of this revised proposal is that of the September 2008 quarter. EnergyAustralia, therefore, has updated its estimates of inflation for the 2008 FY with actual CPI data using:

- The change in the sum of four quarters actual CPI from the 2007 FY to 2008 FY. That is, the change in the sum of four quarters to June CPI. The resulting actual inflation is applied to adjust the distribution opening RAB.
- The change from the June 2007 quarter CPI to the June 2008 quarter CPI. That is, June on June quarter change in CPI. The resulting actual inflation is applied to the transmission opening RAB.

EnergyAustralia has incorporated the following estimates of inflation for the 2009 FY:

- The change in the sum of four quarters actual CPI to September 2007 and September 2008. This is applied to adjust the distribution closing RAB.
- The change from September 2007 to September 2008. This is applied to adjust the transmission closing RAB.

At the time of making its final determination, EnergyAustralia proposes that the AER adjusts the opening RAB to reflect the updated estimate of inflation for 2009 FY using the March 2008 – March 2009 comparison.

Reconciliation to June 2008 proposal

The revised value of EnergyAustralia's opening RAB as at 1 July 2009 is $8,403 million. Of this total, $7,346 million is for assets classified as distribution (other than dual function assets) and $1,058 million is for assets classified as transmission (dual function assets).

Tables 2.1 and 2.2 show the updated inputs used to calculate the revised opening RAB.

Table 2.1 Distribution

	As per original proposal	Updated
2007-08 net capex	$808.9 m	$796.1m
2007-08 FY inflation	2.8%	3.4%
2008-09 FY estimated inflation	2.8%	4.2%
2003-04 FY real pre-tax WACC	7.0%	7.5%
Value of asset transferred to transmission	($57.2m)	($58.3m)

Table 2.2 Transmission

	As per original proposal	Updated
2007-08 net capex	$51.7m	$101.6m
2007-08 FY inflation	4.2%	4.51%
2008-09 FY estimated inflation	4.2%	4.98%
Nominal vanilla WACC for 2004-09.	8.92%	9.08%
Value of asset transferred from distribution	$57.2m	$58.3m

The table below shows the reconciliation of the revised opening RAB value from our June 2008 proposal.

2. Regulatory asset base

(continued)

Table 2.3 Reconciliation of revised opening asset base to June 2008 proposal ($ million, nominal)[9]

	Total	Other Distribution	Transmission (dual function)
Opening RAB as per original proposal	8,218	7,229	989
Add/(less): increase/(reduction) in net capex[10]	48	(5)	53
Add/(less): reduction/(increase) in regulatory depreciation	135	124	11
Add: Increase in difference between actual and forecast capex for 2003-04 (including return on difference)	2	2	0
Add/(less): increase/(reduction) in value of asset transferred	0	(1)	1
Add/(less): increase/(reduction) in non system asset re-allocation	0	(3)	3
Revised opening RAB	**8,403**	**7,346**	**1,058**

[9] Numbers may not add due to rounding.
[10] Includes half WACC return.

3-6. Capital expenditure

REVISED PROPOSAL

EnergyAustralia has revised its June 2008 building block proposal (June 2008 proposal) for the total of forecast capital expenditure. The revised total of forecast capital expenditure is $8.303 billion (or, $8.482 billion including equity raising costs).

As explained in Chapter 13 of this revised proposal, EnergyAustralia has revised its energy forecasts to address the matter raised in the AER's determination concerning the most up to date energy forecasts. EnergyAustralia made consequential updates to the peak demand forecasts to ensure there is consistency with the information underlying both the energy and peak demand forecasts.

EnergyAustralia's capital expenditure forecast has been revised to incorporate the most up to date peak demand forecasts. The updated peak demand forecasts take account of our estimated impact of the Carbon Pollution Reduction Scheme (CPRS) and lower economic growth forecasts. The consequent impact of the updated peak demand forecast on EnergyAustralia's forecast capital expenditure is a reduction of $234 million from the June 2008 proposal. This includes a reduction of $85 million for Area Plans, $100 million for 11kV, $ 46 million for LV plan and $3 million for other capital expenditure.

EnergyAustralia has also made revisions to the forecast capital expenditure to incorporate the substance of changes required to address the matters raised in the AER's determination regarding:

- adjustments to expenditure on feeders 908 and 909, which results in an $8 million reduction the June 2008 proposal.
- the AER's decision re-assigning customers from one tariff class to another, which restricts the application of tariff based demand management resulting in a $30 million increase in capital expenditure.
- updating cost escalators and corrections for the application of escalators which results in a $145 million reduction from the June 2008 proposal
- adjustments to the cash flow model for equity raising costs and the AER's preference for equity raising costs to be capitalised, which result in a $179 million increase from the June 2008 proposal.

This chapter together with chapters 3-6 of EnergyAustralia's June 2008 proposal (including all attachments and supporting information submitted in support of those chapters) now comprise EnergyAustralia's current proposal in relation to forecast capital expenditure. There are a number of additional attachments referred to in this chapter which should now be read in conjunction with attachments to the June 2008 proposal. Specifically Attachment 3A should now be read in conjunction with Attachments 5.1 and 5.3. Attachment 3B should be read in conjunction with Attachment 5.7, Attachment 3C should be read in conjunction with Attachment 5.9, Attachment 3D should be read in conjunction with Attachment 5.10, Attachment 3E should be read in conjunction with Attachment 5.13, Attachment 3I should be read in conjunction with 5.15, Attachment 3M should be read in conjunction with Attachment 5.14, Attachment 3O should be read in conjunction with Attachment 8.2. Figures and tables in the June 2008 proposal which refer to forecast energy and peak demand growth or capital expenditure for the 2009-2014 regulatory control period, may no longer be totally accurate but are still appropriate for illustrative purposes.

Rule requirements

The distribution determination is predicated on a decision in which the AER either:

(i) acting in accordance with clause 6.5.7(c) accepts the total of forecast capital expenditure for the regulatory control period that is included in the current building block proposal; or

(ii) acting in accordance with clause 6.5.7(c) does not accept the total of forecast capital expenditure for the regulatory control period that is included in the current building block proposal, in which case the AER must set out its reasons for that decision and an estimate of the total of the DNSP's required capital expenditure for the regulatory control period that the AER is satisfied reasonably reflects the capital expenditure criteria taking into account the capital expenditure factors. (Clause 6.12.1.(3))

3-6. Capital expenditure (continued)

Our June 2008 building block proposal

EnergyAustralia proposed a total capital expenditure requirement for the regulatory control period of $8.66 billion (FY09 real).

AER's draft determination

The AER did not accept EnergyAustralia's forecast capital expenditure in the June 2008 proposal. The AER's estimate of EnergyAustralia's required capital expenditure for the next regulatory period is $8.43 billion (excluding equity raising costs). The AER:

- Corrected errors of $56 million relating to cost escalation and cost allocation.
- Reduced total capital expenditure by $111 million to adjust for modified cost escalators.
- Reduced reliability expenditure by $16 million to remove EnergyAustralia's "blackspot" reliability expenditure on the basis that it did not reflect the objectives of clause 6.5.7(a).
- Reduced zone substation expenditure by $34 million on the basis that the AER is not satisfied that zone substation costs reflect efficient cost.
- Reduced total capital expenditure by $8 million on the basis that expenditure on replacement of feeders 908 and 909 does not comply with Clause 11.6.19 of the Transitional Rules.
- Reduced equity raising costs from $49 million to $36 million. The AER also indicated its preference that equity raising costs be included in forecast capital expenditure rather than in the forecast operating expenditure.

Our response to the AER's draft determination

EnergyAustralia rejects the AER's decision to reduce the capital expenditure forecasts as we consider the forecasts reasonably reflects the costs of meeting our regulatory obligations and more broadly, the capital expenditure objectives. Our proposal was based on sound and detailed planning assessments. The program once defined, is subject to internal governance processes that delivers a high degree of assurance with regard to the prudence and efficiency of the program. It should also be noted that the bulk of program will be subject to competitive tendering processes which also ensures efficient outcomes will be delivered throughout the forthcoming period. EnergyAustralia does not accept that cuts to capital expenditure are warranted given the robust nature of the planning and delivery processes within EnergyAustralia.

Since the preparation of the June 2008 forecasts, significant changes have occurred that impact the key drivers of energy volume growth. EnergyAustralia considers that in updating its forecast, all relevant new information should be taken into account as it would not be prudent to update the forecast for some new information and not others. EnergyAustralia has therefore revised both its energy and peak demand forecasts. The revised forecasts are detailed in Section 3.1.

Sections 3.2 and 3.3 outline the impact of the updated system peak demand forecast will impact on capital expenditure and demand management. Section 3.3 discusses the revisions to the impact of tariff based demand management to address the changes necessitated by the AER's decision on the assignment of customers to tariff classes.

We address the matters raised in the AER's decision in the following sections:

- Section 3.4 sets out the reasons why we do not accept the AER's findings to reduce total capital expenditure by $111 million to adjust for real cost escalators.
- Section 3.5 sets out the reasons why we do not accept the AER's finding to reduce reliability expenditure by $16 million on the basis that "blackspot" reliability expenditure was not reflective of the objectives of clause 6.5.7(a).
- Section 3.6 sets out the reasons why we do not accept the AER's finding to reduce zone substation expenditure by $34 million.
- Section 3.7 sets out the reasons why we do not accept the AER's finding with respect to the indirect cost of raising equity. This section also revises our proposal for the matter raised by the AER with respect to cash flow modelling and the AER's preferred treatment of equity raising costs as capital expenditure.

A summary of EnergyAustralia's revised forecast of capital expenditure is set out in section 3.8.

EnergyAustralia accepts the AER's draft decision with respect to the following factors and revises the forecast capital expenditure to take them into account:

- Correction of errors of $56m relating to escalation and cost allocation (discussed in section 3.4).
- Reduction of capital expenditure by $7.6 million to reflect approved expenditure for replacement of feeders 908 and 909 (noted in section 3.2).

3.1 Revised peak demand forecast

Chapter 4 of our June 2008 building block proposal notes that EnergyAustralia's capital program relies in part on forecasts of peak demand. For large capital works, peak demand is forecast on a spatial basis (i.e. at each zone substation). However, for other parts of the network (i.e. the distribution network) forecasts of capital expenditure rely on global or regional estimates of peak demand.

The AER rejected EnergyAustralia's energy forecast on the basis that it was outdated. In order to provide a reasonable expectation of the energy forecast, (including addressing the reasons for the AER's rejection of the energy forecast in our June 2008 proposal), it is necessary for EnergyAustralia to extend the revision of the forecast (requested by the AER) to take account of all new information that has become available since the original forecasts were prepared.

In doing so, EnergyAustralia's revised proposal takes account of the most recent projections of economic activity and considers the impact of key factors such as the CPRS scheme and other pricing impacts that will drive increases in prices at the retail level. This is consistent with EnergyAustralia's standard approach to demand forecasting which was set out in Attachment 13.2 to the June 2008 proposal.

System demand will also be affected by the level of economic activity and expected price increases. As a consequence of revising the energy forecast, EnergyAustralia has also revised its peak demand forecast. This has resulted in changes to the capital forecast.

The AER considered that EnergyAustralia's peak demand forecast methodology and the peak demand forecast in its June 2008 proposal provided a realistic expectation of the demand for standard control services. EnergyAustralia has maintained the same methodology used in the June 2008 proposal when updating its forecast peak demand for this revised proposal.

EnergyAustralia's comments

Customer number forecasts

The AER accepted EnergyAustralia's forecast of customer connection capital expenditure in its draft determination. However, the AER requested that EnergyAustralia update its forecast of customer numbers and its energy forecast using more up to date information from 2007-08. EnergyAustralia provided this information to the AER on 29 October 2008. The AER, in its draft determination noted that EnergyAustralia's 29 October 2009 information on customer numbers is an appropriate input into the PTRM, and accepted the forecast under clause 6.12.1(10) of the Rules[11].

The adjusted forecast uses actual customer numbers for 2007-08 and applies the same increase in customer numbers per year as was incorporated into the June 2008 proposal. This means that the total of customer numbers over the forecast period has reduced slightly, but the capital forecast has not changed as the change in customer connections year on year remains the same. The updated customer number forecast, as requested by the AER, does not impact the capital expenditure required for customer connections. Therefore EnergyAustralia has not revised its forecast of customer connection driven capital expenditure.

EnergyAustralia's forecast for capital expenditure driven by customer numbers is based on work by Evans & Peck [12] which links new customer numbers with dwelling approvals. EnergyAustralia has reviewed recent forecasts of dwelling approvals from a number of sources and found there is considerable uncertainty over the timing and magnitude of the forecast recovery in NSW. Given the divergent views with respect to dwelling approvals, EnergyAustralia does not consider that there is justification to further update its forecasts

[11] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p116.

[12] Attachment 5.8 to EnergyAustralia's June 2008 proposal – (Customer Connections - Capital Requirements - Evans & Peck)

of customer numbers from the updated forecasts provided to the AER in October 2008. Accordingly, EnergyAustralia accepts the AER decision in relation to customer number forecasts.

Peak demand forecasts

EnergyAustralia's total forecast capital expenditure included in its June 2008 regulatory proposal was based on data available up to the end of March 2008. Important developments with respect to key drivers of volume growth have emerged since March 2008:

- The outlook for economic growth over the regulatory period has deteriorated.
- The timing and magnitude of the electricity price impacts including the CPRS, various NSW government levies and the AER's draft determination for the period 2009-10 to 2013-14 have become more certain.

These developments have impacted peak demand forecasts. EnergyAustralia has accounted for the impact of these developments on peak demand forecasts and capital expenditure in revising its proposal.

During the AER Pre-Determination conference on 9 December 2008 the potential impact of CPRS was raised by Chris Dunstan of the Institute of Sustainable Futures. A number of participants also requested that forecasts be reviewed to consider the impact of the present economic circumstances.

EnergyAustralia agrees that the present economic circumstances and forecast increase in electricity prices in general will impact both energy volumes and peak demand. Accordingly, EnergyAustralia has prepared revised energy volumes and peak demand forecasts for the 2009-10 to 2013-14 determination period.

EnergyAustralia's revision to the peak demand forecast for the 2009-14 period is as follows:

Table 3.1 Average Peak Demand Growth (2009-14)

Proposals	Annual growth rate
June 2008 proposal	2.8% p.a.
January 2009 revised proposal	2.7% p.a.

Detail of how the peak demand forecast was revised is presented in Attachment 13A to this revised proposal ("Revised Energy & Peak Demand Forecasts to 2014 *"*). The change to EnergyAustralia's energy forecast is also discussed in Chapter 13 of this revised proposal in relation to X-factors.

In summary, EnergyAustralia has revised its peak demand forecasts to:

- consider revised outlooks for economic growth; and
- account for the timing and magnitude of price increases resulting from the CPRS, various NSW government levies and the AER's draft determination.

The revised growth rate for the peak demand forecast for the 2009-14 period is 2.7% p.a.

3.2 Impact of revised peak demand forecast

The reduction in peak demand will impact the capital expenditure required to provide increased capacity over the 2009-14 period. Capacity driven expenditure contained in the following plans will be impacted:

- Area Plans;
- 11kV Development Plan; and
- Low Voltage Capacity Plan.

The capital forecast in each of these plans has been considered and adjustments have been made where appropriate. The revised capital forecast in respect of each of these plans is described in the sections below.

There will also be a small change ($3m) in the category of other capital expenditure primarily arising from changes to System IT and planning and development costs.

Area Plans

EnergyAustralia's Area Plans detail system development requirements to meet capacity, reliability, replacement and infrastructure standards issues on the transmission and subtransmission networks. As investments are holistically planned, many projects address multiple drivers. Hence changes in forecast demand will impact only those projects whose timing is dictated by peak demand considerations.

EnergyAustralia has carried out a high level review[13] of the impact of the reduced peak demand forecast by deferring capacity driven projects which were due for completion after 1 January 2012 by up to 12 months.[14]

The impact of the review of area plans is shown in Table 3.1. This also includes the adjustments to the expenditure on Feeders 908 909 based on the AER's determination. We accept the AER's findings on this matter and revise our proposal to reflect this adjustment. The table also demonstrates our revisions to cost escalation and corrections discussed in section 3.4 of this revised proposal.

Despite the high level nature of the review, EnergyAustralia considers its assessment of the impact of reduced peak demand is appropriate to forecast the likely deferral of the capital expenditure program and calculation of the subsequent reduction to the capital expenditure forecast.

Table 3.2 Revised Area Plan Expenditure ($2008-09 million real)

	2010-14	FY10	FY11	FY12	FY13	FY14
June 2008 proposal [15]	3,949.3	730.6	742.2	897.8	838 7	740.0
908-909 Adjustment	-7.6	-6.4	-1.2			
Escalation Adjustments[16]	-139.3	-1.3	-15.3	-38.3	-36.0	-48.4
Adjustment for Forecast	-84.9	-0.4	-7.3	-56.3	2.0	-23.0
Revised proposal[17]	**3717.5**	**722.5**	**718.4**	**803.2**	**804.7**	**668.6**

11kV Development Plan

EnergyAustralia used its 11kV Network Development model to determine required levels of capital expenditure to address capacity issues on the 11kV system. This model has been rerun with the revised peak demand forecast.

The model uses a regional growth forecast, derived from the peak demand forecast, to model future network requirements. The model output has been adjusted to account for expenditure included in other parts of EnergyAustralia's proposal using the methodology applied in EnergyAustralia's June 2008 proposal[18]. The results of the revised forecast (including the impact of revised cost escalation) on required 11kV capital expenditure are indicated in table 3.2 below.

[13] A detailed review is not possible within the required timeframe and would require revision of the spatial forecasts, which do not reflect the full impact of present circumstances.

[14] EnergyAustralia, *Impact of revised demand forecast on Area Plans*, January 2009 (Attachment 3A)

[15] Includes property purchases

[16] Adjustment to cost escalators is discussed in section 3.4

[17] Numbers may not add due to rounding

[18] EnergyAustralia, *Revised 11kV Distribution Mains Capital Requirements 2009-2014*, January 2009 (Attachment 3B)

3-6. Capital expenditure (continued)

Table 3.3 Revised 11kV Development Model expenditure ($2008-09 million real)

	2010-14	FY10	FY11	FY12	FY13	FY14
June 2008 proposal	698.3	59.4	110.1	166.8	172.3	189.7
Escalation Adjustments	-2.5	0.5	1.7	1.2	-1.2	- 4.7
Adjustment for Forecast	-99.7	-0.1	-2.1	-15.7	-26.1	-55.7
Revised proposal[19]	**596.1**	**59.8**	**109.7**	**152.3**	**144.9**	**129.4**

Low Voltage (LV) Plan

EnergyAustralia's forecast of expenditure on increasing capacity on its distribution substations and LV network is based on work carried out by Evans & Peck[20]. The analysis used regional growth forecasts, derived from the peak demand forecast.

At the request of EnergyAustralia, Evans & Peck has updated its expenditure forecast to account for the most recent peak demand forecast[21]. The Evans & Peck results have been adjusted by EnergyAustralia using the methodology applied in EnergyAustralia's June 2008 proposal to account for changes in load survey costs and actual levels of augmentation expenditure prior to the 2009-14 period.[22] The results of the revised forecast (including the impact of revised cost escalation) on required LV works are indicated in table 3.3 below.

[19] Numbers may not add due to rounding

[20] Attachment 5.9 to the June 2008 proposal (Low Voltage network Capital requirements, Evans & Peck November 2007)

[21] Evans and Peck, *Impact Of Revised Demand Forecasts On Capital Requirements For Distribution Substations And Low Voltage Distributors*, December 2008 (Attachment 3C)

[22] EnergyAustralia, *Revised Distribution Substation & LV Network Capital Requirements 2009-14,* January 2009 (Attachment 3D)

Table 3.4 Revised Low Voltage Development Model ($2008-09 million real)

	2010-14	FY10	FY11	FY12	FY13	FY14
June 2008 proposal	294.7	52.4	53.7	62.3	63.2	63.1
Escalation Adjustments	3.7	1.1	1.5	1.4	0.4	-0.7
Adjustment for Forecast	-45.9	-12.2	-5.6	-13.2	-10.7	-4.2
Revised proposal[23]	**252.5**	**41.3**	**49.6**	**50.5**	**53.0**	**58.2**

Conclusion

The revised forecast peak demand forecast, in response to updated information, has reduced the total capital expenditure required over the period.

In our June 2008 proposal we noted the consideration given to alternative capital expenditure profiles over the period. In particular, in chapter 5 of the June 2008 proposal, we noted that the delivery of our capital expenditure requirements consisted of adopting a smoothed profile of total capital expenditure and a deliverability strategy.

Changes to peak demand forecast and the consequent reduction in our capital expenditure requirements will improve our ability to deliver our capital program.

The adjustments to our various plans are based on a sound and transparent methodology broadly consistent with our original proposal and in light of a more realistic expectation of demand forecasts (based on updated information) is a reasonable reflection of the capital expenditure required over the period.

EnergyAustralia has revised its forecast capital expenditure to incorporate the most up to date peak demand forecasts. This results in a $234 million reduction in forecast capital expenditure including $85 million for Area plans, $100

[23] Numbers may not add due to rounding.

million for the 11kV plan $46 million for the LV plan and $3 million for other[24] capital expenditure. The revision to Area plans also includes an additional adjustment of $8 million to expenditure on 908 and 909 feeders in accordance with the AER's finding on this matter.

3.3 Demand management

There are two types of demand management (DM) –

- project based demand management, which is undertaken to defer specific capital investment in a specific location; and
- tariff based demand management, which impacts overall system demand.

EnergyAustralia investigated whether the reduction in the rate of forecast demand growth and capacity related expenditure will impact project based DM.

EnergyAustralia also assessed the impact of tariff based DM from the AER's draft determination. The AER's decision on assigning customers to tariff classes restricts the circumstances in which EnergyAustralia can move customers between tariff classes. This will severely restrict the application of tariff based DM in the 2009-14 period.

Project Based DM

In our June 2008 proposal, we analysed the impact of project based DM on our capital program. This analysis found that the reduction to EnergyAustralia's program arising from project based DM was below the level of reduction applied by EnergyAustralia in its capital smoothing process. Consequently no adjustment was made to the program to account for the impacts of project based DM.

This analysis has been reviewed to consider the impact of changes to the peak demand forecast.[25] The impact of project DM is expected to decline marginally and will continue to remain below the level of reductions resulting from smoothing of the capital program. There is therefore no reason to modify EnergyAustralia's revised capital program to account for changes in project based DM.

The reduced level of augmentation expenditure will change the operating expenditure costs associated with project Demand Management. This is discussed in Section 9.9 of this proposal.

Tariff based DM

Tariff based DM uses time of use (ToU) pricing signals to influence customer behaviour. This is likely to reduce overall demand or to shift demand from peak to shoulder periods.

EnergyAustralia accounted for the impact of tariff based DM in our June 2008 proposal by adjusting the capital expenditure forecast at the global level by assessing the expected value of capital expenditure that could be deferred beyond the 2009-14 period.

The AER's determination on re-assigning customers to other tariff classes severely restricts the application of tariff based DM in the 2009-14 period[26]. EnergyAustralia notes in Chapter 1 of Part III of this revised proposal that we do not agree with the AER's decision. A key issue is that the AER's decision does not allow EnergyAustralia to pursue the deferral of network capital expenditure through tariff initiatives, as the circumstances in which existing customers can be transferred to another tariff is severely restricted.

Consequently EnergyAustralia considers that the previous assessment of the impact of tariff based DM no longer represents a reasonable forecast of the impact of tariff based demand management. Accordingly EnergyAustralia has removed the impact of tariff based DM from its capital expenditure forecasts.

A change to the AER decision to enable the transfer of existing customers, to another tariff class, where time of use metering

[24] Other expenditure includes system IT and planning and development costs.

[25] EnergyAustralia, *Revised DM Impact on 2009-14 Capital Forecast* , January 2009 (Attachment 3E)

[26] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p21.

was installed, would enable a potential reduction in capital expenditure of $29.5 million.[27]

EnergyAustralia has revised its forecast capital expenditure by $30.6 million for the impact of tariff based DM. This is to incorporate the change required by the AER's decision on the procedure for assigning customers to tariff classes which results in a $29.5 million increase in forecast capital expenditure. A further increase of $1.1 million arises from changes to the capital program.

3.4 Cost escalation

The AER's draft determination rejects EnergyAustralia's application of input cost escalators to its capital program. The AER stated that EnergyAustralia's escalators did not reasonably reflect a realistic expectation of the cost inputs required to achieve the capital expenditure objectives.

Specifically, the AER:

- rejected the use of producer escalators;
- removed the effect of EnergyAustralia's assumed six month lag in input prices for key equipment costs;
- rejected EnergyAustralia's methodology for deriving cost escalators and substituted alternative data sources and methodologies to calculate the cost escalators;
- removed the real cost escalation of expenditure on wood poles; and
- corrected errors in the application of cost escalation to EnergyAustralia's capital forecast model.

EnergyAustralia's comments

EnergyAustralia does not accept the AER's findings with respect to EnergyAustralia's cost escalation methodology.

EnergyAustralia considers that the methodology of deriving cost escalators is a reasonable method to apply in the circumstances in our June 2008 proposal:

Clause 6.5.7(c) states that the AER must accept the total capital expenditure forecast if it is satisfied that:

- the total forecast reasonably reflects the efficient costs of achieving the capital expenditure objectives,
- the costs that a prudent operator in the circumstances would require to achieve the capital expenditure objectives, and
- a realistic expectation of peak demand forecasts and cost inputs.

EnergyAustralia considers that the AER has not provided adequate reasons for its decision that EnergyAustralia's forecasts of cost escalators do not represent a realistic expectation of cost input.

We note that the AER's discretion to reject our methodology is limited by the provision of Transitional Rule 6.12.3 which states that if the AER rejects our methodology, it must only substitute a methodology on the basis of the current regulatory proposal and only to the extent necessary to enable it to be approved under the rules.

Further, EnergyAustralia considers that there are inconsistencies in the methodology proposed by the AER that make the substituted escalators unrealistic.

Detailed reasons for EnergyAustralia's rejection of the AER's findings are presented below. Our comments are supported by CEG as set out in Attachment 3I.[28] EnergyAustralia also engaged Price Waterhouse Coopers to independently assess the reasonableness of the approval adopted by CEG in the original report and the reasonableness of the AER in rejecting the approach adopted by CEG.[29]

EnergyAustralia's comments are set out in two sections:

[27] This compares with the June 2008 proposal impact of $31.1 million. The change was attributable to a reduction in demand ($1.1 million) and changes to the value of the capital program due to updated cost escalators($0.5million).

[28] CEG, *Escalators affecting capital forecasts*, January 2009 (Attachment 3I).

[29] Price Waterhouse Coopers, *Independent report of CEG method*, 12 January 2008 (Attachment 3J).

- issues arising from the difference in methodology applied by AER and EnergyAustralia; and
- issues relating to specific cost escalators.

EnergyAustralia accepts that its capital forecast must be revised to update for recent information and to correct inadvertent errors applied in the application of cost escalators in the June 2008 proposal. EnergyAustralia has revised the capital expenditure forecast to correct for these errors, and has taken into account up to date market data.

EnergyAustralia also accepts the AER findings with respect to:

- indirect labour costs associated with processing materials;
- construction cost escalators; and
- interpolation of LME and Consensus forecasts; and
- land and easements.[30]

3.4.1 General methodology

This section addresses the following methodological issues:

- Producer escalators
- Independent forecasts
- Lagging escalators
- Use of averaging in calculating cost escalators
- Internal consistency of data
- Timing of commodity price movements.

Producer escalators

The AER noted in its draft determination that the methodology recommended by CEG goes beyond that approved by the AER in its decision for SP AusNet in that it includes estimates of the following factors:

- variances in prices charged by equipment manufacturers to reflect their market power (producer margins)
- the proportion of general labour costs used in the manufacture of electrical equipment (producer labour costs)
- indirect general labour costs associated with the processing of raw materials (eg. steel).

The AER indicates that these additional cost factors depart from how it intended to account for the impact of the commodity boom and skilled labour shortages. It is concerned that including these factors in the cost escalation will offset declines in commodity prices so the approach is no longer symmetrical.

The AER also argues that including the above factors in estimates:

- compensates a regulated business at a fine level of detail and go beyond the AER's general obligations to provide a reasonable opportunity to recover efficient costs; and
- may be duplicative as they are already included in base unit cost estimates.

Finally the AER questions the extent to which these forecasts will be subject to real growth and whether they can be accurately forecast.[31]

EnergyAustralia does not consider that the AER's reasoning has a legitimate basis in the Rules, nor is a legitimate response to its claims of forecast uncertainty. In particular:

- The AER's reference to clause 6.5.7(c) infers that the clause contains guidance as to the specific types of costs that should be incorporated into the forecast. Rather, the clause requires that the forecast costs reasonably reflect efficient costs of a prudent operator and be a 'realistic' expectation of cost inputs.
- The AER rejects these components on the basis that they represent a finer level of detail than they envisage in their

[30] EnergyAustralia agrees with the AER's approach of interpolating between the last LME forward price and interpreting the Consensus Economics 5-10 year forecast as effectively being a 7.5 year forecast as reasonable.

[31] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p532.

preferred methodology. EnergyAustralia considers that the Rules do not envisage that legitimate costs be discounted because they arise from analysis at a fine level of detail.

- Given CEG's assumptions are supported by economic principles, it is not clear how inclusion of these components in a cost forecast methodology could lead to an asymmetric outcome for cost escalators provided the method is applied consistently across time.
- EnergyAustralia does not believe that uncertainty over the level of cost is a legitimate reason to completely reject it as a cost per se, but rather, should prompt investigation of alternative estimates or an alternate method to forecasting cost changes.

In summary, the AER has not provided adequate reasons for its decision to reject a legitimate cost forecast methodology. The cost components used in EnergyAustralia's forecast are costs faced by distributors have been estimated using a reasonable method, and have been based on available market information. These cost components should be considered as part of the cost escalation methodology in order to provide a realistic forecast of future costs faced by distribution businesses.

EnergyAustralia acknowledges that the drivers of cost pressures can change over time, but the methodology of forecasting cost movements by reference to a detailed build up of cost components remains a reasonable and prudent methodology to apply to forecasting material cost movements.

The following sections address the specific producer escalators.

Producer margins

EnergyAustralia maintains the appropriateness of the methodology applied with respect to producer margins and we do not revise the *method* for forecasting cost escalators using a producer margin. However, we accept that current market conditions have lowered producer margins.

EnergyAustralia has therefore revised its *forecast amount* of these cost components to take account of more up to date economic data. In summary, the cost component of producer margin has been revised to 0% to reflect softening international economic conditions.

Producer labour costs - skilled

EnergyAustralia considers it is not reasonable to expect equipment suppliers to absorb rising labour costs at a time when their customers are significantly increasing their demand for equipment. EnergyAustralia maintains the position in its June 2008 proposal that labour inputs into materials will be passed through to equipment prices in these circumstances.

EnergyAustralia sources transformers locally and notes the production of power transformers requires highly specialised non-electrical labour. Given the significant increase in approved capital investment programs in NSW alone, EnergyAustralia considers it is a reasonable assumption that skilled labour input costs will be passed through to local customers. This applies to domestic manufacturers which rely on Australian, rather than international, labour and equipment markets. Domestic manufacturers are partially protected from international competition due to distance and freight costs.

EnergyAustralia accepts that it is difficult to establish an appropriate labour market index to incorporate international labour market costs in forecasts of international equipment prices, particularly during uncertain world economic conditions. While EnergyAustralia believes labour costs will be passed on, our ability to forecast movements in international labour costs is limited.

EnergyAustralia has not revised its *method* for forecasting cost escalators using labour and producer margin components of costs.

EnergyAustralia has revised its *forecast amount* of these cost components to take account of more up to date economic data:

- Producer skilled labour cost component of domestically sourced equipment has been set at the general labour rate.
- Producer skilled labour cost component of internationally sourced equipment has been set to 0%.

Producer labour costs - unskilled (general)

EnergyAustralia has not revised its *method* for forecasting cost escalators using labour and producer margin components of costs.

EnergyAustralia has revised its *forecast amount* of these cost components to take account of more up to date economic data:

- Producer unskilled cost component of domestically sourced equipment has been set at 0%
- Producer unskilled cost component of internationally sourced equipment has been set to 0%.

Materials processing labour

EnergyAustralia notes; and has applied, the AER's decision on the indirect labour costs associated with processing raw materials.

Independent forecasts

In its draft decision, the AER dismissed CEG's approach of using an average of independent forecasts and has adopted its own approach, reflecting what appears to be a prior view that it would apply its own methodology as per its decision for SP AusNet.[32] EnergyAustralia does not believe the Rules allow the AER to reject EnergyAustralia's proposed approach and apply its own approach where an valid method has been proposed. The AER must address itself to the proposal put by EnergyAustralia and only substitute its own forecast to the extent required to result in a reasonable forecast of costs as per clause 6.12.1(3).

EnergyAustralia is concerned that the AER has imposed its own preferred methodology without regard for the validity of alternate approaches proposed by EnergyAustralia. We do not believe this is consistent with the decision making process under the Rules. Furthermore, EnergyAustralia is concerned with the AER's reliance on a single economic forecaster.

Notwithstanding the concerns above, EnergyAustralia has applied the Econtech forecasts used by the AER. However, EnergyAustralia considers the use of several forecasts actually increases the reliability of the estimate, as it captures more information and more assessments from different perspectives. EnergyAustralia considers that if the AER continues to rely on a single economic forecaster for anticipated movements in labour and construction costs, it should consult with businesses if these forecasts are updated. This will ensure appropriate scrutiny is applied to the forecasts and they can be independently verified if necessary.

Lagging escalators

EnergyAustralia applied the CEG escalators to its materials forecast with a lag of six months to reflect an average time taken for commodity price changes to be reflected in equipment prices.

The AER rejected the application of a lag for EnergyAustralia despite a similar method being applied and approved by AER in its ElectraNet Determination in April 2008 and SPAusNet Draft Determination. The AER quoted from its decision for SPAusNet that:

> On the balance of available information, SKM's assumption of a lag between base metal prices and transmission equipment prices appears reasonable.[33]

EnergyAustralia considers that the AER's finding for SPAusNet was correct and that it should have accepted EnergyAustralia's proposed lag of six months on the same basis.

The use of a lag in input prices for key equipment costs reflects actual current contracts held by EnergyAustralia and standard contracting practices in the industry. Not only is the forecast lag consistent with EnergyAustralia's actual contract arrangements, it is also consistent with cost forecasts of other regulated utilities which have been approved by the AER.

The AER's rejection of EnergyAustralia's inclusion of the lag effect for input prices were based on CEG modelling of a 12 month lag, not EnergyAustralia's actual proposal (which was for a 6 month lag). In any case, the AER's reasons for rejecting the CEG 12 month lag were based on an incorrect comparison of PPI and LME data (outlined below).

In its June 2008 regulatory proposal, EnergyAustralia submitted supporting information to the AER that this lag was based on pricing arrangements built into period contracts currently in

[32] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p532.

[33] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p561.

place at EnergyAustralia.[34] Neither the AER nor Wilson Cook asked to verify this information, nor at the time was this matter discussed. EnergyAustralia had no reason to believe that Wilson Cook was not completely satisfied with this response.

The AER's consideration of EnergyAustralia's proposal based on modelling using a one year lag in the CEG report is misdirected and not permitted under the Rules. The AER is required to consider EnergyAustralia's proposal and if not satisfied in relation to that, to only adjust for such amount as would enable it to be satisfied. Under clause 6.12.1(3) of the Rules, the AER can only amend the proposal as much as is necessary for it to be satisfied that it reasonably reflects the capital expenditure criteria. The AER must accept some allowance for a lag effect where there is evidence of this effect.

Further, any decision over a lag effect must be evidentially based. In the absence of any other evidence, the AER can not reasonably reject EnergyAustralia's revised proposal, which is fully supported. While the AER appears to acknowledge that a 3-6 months lag would be supported by the evidence[35], it goes on to suggest that in fact there is no such effect. EnergyAustralia does not accept the AER analysis that there is no lag effect and has provided example clauses from current contracts to the AER to allow it to verify the existence of lags in contracts and reverse its decision to set lags to zero.[36]

The AER included analysis in its draft determination comparing producer price index (PPI) data with actual commodity price movements as evidence that there was no lag between equipment and material prices. The PPI data used relates to input costs and not finished equipment prices. The AER is therefore comparing two like variables:

- commodity prices based on LME prices; and
- commodity prices based on prices paid by local electrical manufacturers

[34] Supporting information to the June 2008 regulatory proposal: (*Estimation and cost indexation process April 2008*), p11.
[35] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p564.
[36] EnergyAustralia, *Material equipment contracts arrangements demonstrating lagging escalator* (Attachment 3F)

This comparison is inappropriate.

EnergyAustralia maintains its view that a lag of 6 months represents a realistic expectation of costs for the lag impact of input prices.

Use of averaging in calculation of cost escalators

EnergyAustralia derived its escalators for commodities and labour by averaging forecasts from several sources. In the absence of evidence to establish that one forecast methodology provides an unimpeachable and unbiased estimate, then use of an average of forecasts from reputable forecasters based on accepted (even if differing) approaches allows differences in methodologies to be smoothed, and mitigates potential errors in models and the impact of a single forecaster's judgement being given greater weight. The use of several forecasts actually increases the reliability of the estimate, as it captures more information and more assessment from different perspectives.

The AER has provided no evidence to support why the use of one or more forecasters other than its own preferred forecaster will lead to an unreasonable outcome.

The AER's rejection of the use of averaging in favour of a single forecaster is of concern. EnergyAustralia maintains its position from its June 2008 proposal that averaging a variety of forecasts is appropriate for calculation of real cost escalators. The AER has provided no valid reasons for rejecting CEG's approach and appears to have taken the view that it would adopt its own methodology rather than consider that proposed by EnergyAustralia.

Internal consistency of data

The calculation of materials escalators relies on the use of commodity prices which are commonly priced in US dollars. It is therefore essential that exchange rate assumptions are consistent with commodity price observations. The AER, in calculating its materials escalators has not aligned its exchange rate and commodity price observations and has converted commodity prices observed in October 2008 using an exchange rate forecasts from March 2008.

It is noted that these forecasts were only recently updated at the time of the AER's draft decision but it is important that data used for adjusting costs are estimated on a consistent basis.

The Australian dollar fell significantly in value from $0.926 in March 2008 to $0.689 in October 2008. The new lower exchange rate will produce a markedly different escalation rate than has been calculated by the AER for use in its draft determination. It is essential that material prices and exchange rates be forecast on a consistent basis to ensure the integrity of the forecast.

The exchange rate assumption in the base level capital estimates is critical for goods that are traded internationally such as switchgear and secondary protection systems which are priced in US dollars. EnergyAustralia's capital program was estimated using costs as at December 2006 and an exchange rate of $0.7913. The exchange rate depreciation to $0.6454 in mid December 2008 has led to a change in the cost of this equipment which must be reflected in EnergyAustralia's capital forecast for the 2009-14 period.

EnergyAustralia has not revised its *method* for forecasting cost escalators using consistent observation periods of commodity prices and exchange rates.

EnergyAustralia has revised its *calculation* of the cost escalators to take account of updated exchange rate information. An average exchange rate of $0.64 has been used to calculate costs in this revised proposal.

Timing of commodity price movements

A further issue of concern is the manner in which the movement of prices is calculated.

The AER's forecast of materials cost changes uses a comparison of commodity prices from June to June. This is different to the method used by EnergyAustralia (and used by Econtech) which calculates the costs movements over a year as the average of the four quarter movements over the year.

As previously set out, the AER is not permitted to simply adopt its own methodology without reason, and can only substitute a methodology on the basis of our proposal to the extent to allow it to be consistent with the Rules.

The use of a June on June measure is unduly simplistic and can result in estimates that are significantly different from the actual average yearly movements. This is because of significant volatility in monthly movements of commodity prices. For example using LME data for copper in 2007-08, the June to June measure resulted in a 13.7% decrease in price compared with the yearly average decrease over 12 months of 6.7%.[37] These differences occur because of significant monthly volatility of commodity price movements between months.

EnergyAustralia considers that there is no evidence to suggest EnergyAustralia's methodology is unreasonable. There is no proper basis upon which the AER should depart from the average of four quarters method used by EnergyAustralia and Econtech.

3.4.2 Specific issues

Labour forecasts

EnergyAustralia proposed CEG's method to forecast future movements in labour costs using averaging techniques to come to a consensus of forecasts. CEG used Econtech and Macromonitor forecasts and averaged the two.

The AER in its draft determination did not accept the use of Macromonitor forecasts, saying:

> "The AER also does not consider it appropriate to rely on the forecasts presented by Macromonitor because there is no description of the methodology used to forecast wages growth or productivity."[38]

The AER goes on to note that Macromonitor does not forecast on an equivalent basis to Econtech, particularly in relation to the treatment of productivity. [39]

EnergyAustralia does not accept the AER's reasons for dismissing the use of Macromonitor's forecast for the reasons outlined below.

Productivity

In relation to productivity, EnergyAustralia notes that Econtech produce forecasts that are not adjusted for productivity. To ensure appropriate comparisons, Macromonitor provided labour cost forecasts with a transparent adjustment for

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[37] CEG, *Cost Escalation model*, January 2009 (Attachment 3G)
[38] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p560
[39] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008 p537

productivity. As a result, the two are comparable forecasts that can be used for averaging purposes.

Macromonitor forecast methodology

EnergyAustralia notes that the AER did not seek further information in relation to the Macromonitor forecasts and did not request a description of its modelling techniques.

The AER can only reject the forecast where it is not satisfied that it reasonably reflects a basis on which to forecast costs. This requires some clear basis to conclude that the forecast does not reasonably reflect changes in labour costs. It is not sufficient to reach a conclusion based on unfamiliarity with the methodology or a suspicion that the forecast may not reasonably reflect changes in labour forecasts, without some basis for that conclusion. It is not appropriate for the AER to dismiss a reputable forecast based on its own lack of enquiry.

EnergyAustralia has provided the AER at Attachment 3H with a description of Macromonitor methodology used in forecasting wages growth and productivity to allow it to consider this issue in further detail.[40]

EnergyAustralia also notes AER's comment in relation to econometric techniques. It is not appropriate for the AER to dismiss a forecast on the basis that an independent expert forecaster uses an alternate technique to the AER's preferred forecaster.

Many leading public institutions which are required to make decisions based on forecasting, including the Reserve Bank of Australia, do not solely rely on a single forecaster, nor on the use of a single economic model, but have regard to a variety of forecasts, models and techniques.[41]

EnergyAustralia agrees that Econtech is a reputable economic forecaster. However, Econtech is not the only reputable economic forecaster producing forecasts of future labour cost movements. Further, in the area of forecasting, care should be taken in relation to claims by a forecaster that they are the leading forecaster, if that is intended to imply that they are the best forecaster and that other forecasts have no substantive merit.

If a conclusion that Econtech is a leading forecaster in the sense that there are several forecasters widely used and relied on, then EnergyAustralia accepts this statement. However, there is no basis for concluding that Econtech forecasts are "right" and all other forecasts from which it differs are "wrong".

While Econtech's methodology appears sound, there is an element of judgement in any forecast which results in a degree of subjectivity which is not easily debated or refuted. Placing weight on a single Econtech forecast exposes EnergyAustralia to a significant risk of a single forecaster's judgement.

The methodology underpinning EnergyAustralia's proposal, proposed by CEG is to use multiple forecast sources and apply averaging techniques which we consider provides a sound basis on which to forecast future expenditure. This method mitigates the exposure businesses face to any single forecast methodology or forecaster's judgement.

The AER has proposed to replace the recent Econtech forecasts with updated forecasts. EnergyAustralia does not consider this to be appropriate as the outcomes of this forecast are unknown at this stage and, under the AER's method, will not be subject to comparison with other forecasts or review. There is no basis for concluding in advance that Econtech will provide a forecast that is unimpeachably correct and superior to other forecasts, or that consideration of other forecasts will not assist in deriving reasonably based expenditure forecasts.

EnergyAustralia considers that this concern can be mitigated by the AER consulting with businesses as soon as the updated Econtech forecasts become available will provide EnergyAustralia and other NSW DNSPs with an opportunity to seek independent review of these forecasts if necessary.

[40] Macromonitor, *Forecasts of labour indicators for the Electricity Transmission sector: Forecasting methodology*, 29 August 2008 (Attachment 3H)

[41] CEG, *Escalators affecting capex forecasts*, 5 January 2009 (Attachment 3I)

We note the Rules contemplate the AER publishing any analysis used in forming its decision before the determination is made in its final form.[42]

Notwithstanding the concerns above, EnergyAustralia has revised its proposal to apply KPMG Econtech's labour cost forecasts consistent with the AER's proposed method. However, EnergyAustralia considers further updates of these labour forecasts should be the subject of further consultation.

Construction costs

The AER rejected EnergyAustralia's use of Macromonitor forecasts of construction costs for the same reasons that it rejects the use of Macromonitor's forecast of labour costs.

As set out above, EnergyAustralia considers that the AER's rejection of Macromonitor's forecast is not appropriate, is based on limited enquiry, is based on an unsubstantiated preference for its own modeller, and does not take account of other equally reputable forecasters.

As above, EnergyAustralia's concerns with a single forecaster can be mitigated if the AER consults with businesses regarding Econtech's updated forecasts when they become available.

Despite these concerns, EnergyAustralia has revised its proposal to apply KPMG Econtech's labour cost forecasts consistent with the AER's proposed method. However, EnergyAustralia considers further updates of these labour forecasts should be the subject of further consultation.

Wood poles

The AER notes that EnergyAustralia was the only DNSP to provide a cost escalator for wood poles and suggests that EnergyAustralia has not provided sufficient evidence to justify the existence of a real cost movements for this category of equipment.

EnergyAustralia rejects this statement and draws the AER's attention to historical evidence of real cost movements in timber pole prices. This was provided to the AER following the June 2008 proposal.[43] The information provided in support of a wood pole cost escalator, demonstrated that the average nominal increase in pole prices between 2003 and 2007 was 10.6% for timber poles and 4.1% for concrete poles.

EnergyAustralia forecasts that pole prices will increase by 5% in real terms in 2009-2014. This forecast is based largely on historical cost movements. However, the forecasts also had regard to a Department of Industry (Qld)[44] study into the lack of supply availability of timber suitable for power poles.[45]

The evidence presented to the AER clearly demonstrates that prices have not moved in line with CPI during the 2004-09 regulatory period. The evidence also indicates that the same supply shortages that have led to real cost increases for this product in the last regulatory period will continue to apply in the next period. The AER's refusal to accept the reality of price increases for poles shows selective treatment of evidence and is not consistent with a realistic expectation of future costs for wood poles.

EnergyAustralia maintains its June 2008 proposal which sets a cost escalator for timber poles at a rate of 5% commensurate with historic real price increases. Evidence of historic real price changes and evidence that supply pressures are likely to continue are sufficient grounds upon which to calculate average future real price increases.

In considering this proposal, the AER must assess the evidence provided by EnergyAustralia and the evidence upon which it has based its decision to set the real escalator for timer poles to zero (i.e. only subject to CPI price increases). A decision in relation to this issue, as with all other decisions on the elements of EnergyAustralia's proposal, must be

[42] Clause 6.5.7(e)(3) of the Transitional Rules

[43] EnergyAustralia, *Response to AER questions on cost escalation and reliability targets of September 26 2008*, 3 October 2008 (Attachment 3K)

[44] Department of Primary Industry and Fishery, *Australian Timber Pole Resources for Energy Networks - a Review*, October 2006 (Attachment 3L)

[45] CEG were not used to develop a forecast for pole prices as there is no readily available market price for timber poles other than generic forestry price indexes published by the ABS which are not appropriate for this purpose.

accompanied with reasons which set out relevant values, methods and assumptions.

EnergyAustralia considers that when the AER examines the evidence, it should reasonably conclude that real price changes for timber poles are non-zero and that it is appropriate to apply a real cost escalator to this product based on historic price movements.

Modelling errors

EnergyAustralia acknowledges that there was an error in the application of cost escalators to its capital forecast model. This error resulted in EnergyAustralia inadvertently incorporating an 18 month lag rather than a six month lag between commodity price changes and those changes being seen in equipment prices.

The AER identified this error and EnergyAustralia has corrected for it.

EnergyAustralia has revised its capital forecast to reflect the correct application of its cost escalators to incorporate a six month lag applied as originally envisaged.

3.4.3 Conclusion

EnergyAustralia has revised its total capital expenditure forecast to address the AER's draft decision, by taking account of most up to date information, to determine real cost escalators and to ensure the application of the escalators in its model is correct.

In summary, EnergyAustralia revised:

- producer margins to 0 per cent.
- the skilled labour component of domestically sourced equipment to the general labour rate.
- the skilled labour cost component of internationally sourced equipment to 0 per cent.
- the indirect labour cost component of domestically and internationally sourced equipment to 0 per cent.
- its labour and construction cost forecast consistent with the AER's proposed method to apply KPMG Econtech forecasts.

EnergyAustralia notes the AER has proposed to replace the recent Econtech forecasts with updated forecasts. EnergyAustralia is concerned that this places significant weight on the judgement of a single forecaster which will not be subject to comparison with other forecasts or review. This represents significant risk. EnergyAustralia's concerns with a single forecaster can be mitigated if the AER consults with businesses regarding Econtech's updated forecasts when they become available.

EnergyAustralia has not revised the methodology used to calculate and apply the escalators to its program (except the inadvertent error in the application of these escalators). Rather, we strongly submit the CEG methodology as being appropriate and reasonable as it takes account of more available forecasts, and considers the cost changes over time at a more detailed level than the methodology applied by the AER in its previous regulatory determinations.

EnergyAustralia has revised its forecast capital expenditure to address the matters raised by the AER on using most up to date information to determine real cost escalators and to correct for modelling anomalies. This results in a $145 million reduction to forecast capital expenditure from the June 2008 proposal. A table showing the differences between cost escalators used in EnergyAustralia's June 2008 proposal and this revised proposal is found at Attachment 3Q.

3.5 Reliability expenditure

The AER did not accept EnergyAustralia's forecast capital expenditure of $16 million for the 'blackspot' network reliability program.

The AER did not consider that expenditure associated with the blackspot reliability program, as described by EnergyAustralia, to be consistent with the efficient costs required to achieve the capital expenditure objectives as it is not required to:

- comply with an applicable regulatory obligation or requirement;
- meet or manage the expected demand for standard control services;

- maintain the quality, reliability and security of supply of standard control services; and
- maintain the reliability, safety and security of distribution system through the supply of these services.

In reaching its conclusion, the AER did not accept Wilson Cook's conclusion that the blackspot program was reasonable when considering the method of compliance applied by EnergyAustralia.[46]

EnergyAustralia's comments

EnergyAustralia does not accept the AER's finding that the blackspot reliability program is not consistent with the capital expenditure objectives. The intent of the blackspot reliability program is to allow EnergyAustralia to manage the reliability of the distribution system and to maintain the quality and reliability of supply of standard control services in small pockets of the network. EnergyAustralia submits that:

- the AER has misunderstood the intent of the blackspot program which has been designed to maintain the quality, reliability and security of supply for standard control services to individual customers whose quality of service would otherwise be below the norm;
- the AER erred in rejecting the conclusion of its consultant, Wilson Cook, who considered EnergyAustralia's reliability program to be 'reasonable when based on the method of compliance chosen by EnergyAustralia'[47]; and
- the AER did not approach EnergyAustralia to clarify the drivers for the blackspot reliability program.

As a result of these factors, EnergyAustralia submits the AER has unreasonably rejected this expenditure.

Understanding the blackspot program

EnergyAustralia's blackspot reliability program is necessary to maintain reliability to customers. The DWE Licence conditions framework which uses performance metrics averaged at the feeder (Schedule 3) and feeder category (Schedule 2) provides a coarse measure of distribution system reliability and does not always identify circumstances where the distribution system supplying a small number of customers is poorly performing.

The blackspot reliability program is targeted at maintaining reliability levels for these customers and in so doing, meets the requirements of clause 6.5.7 (a) (3) of the Transitional Rules at a customer level.

EnergyAustralia (like all DNSPs) manages the reliability (and reliability complaints) of individual customers who receive standard control services of unsatisfactory quality.

By rejecting the blackspot program, it appears that the AER has concluded that EnergyAustralia should only rectify reliability shortfalls (in the reliability of the distribution system and of the standard control services) if the feeder to which those customers are connected to, happens to exceed the Schedule 3 Individual Feeder Standards. This is inconsistent with the purpose of the licence conditions.

It is clear from the licence conditions applying in NSW envisage that distributors should invest appropriately to maintain the reliability of services to all customers. For example, the NSW licence conditions provide:

> These conditions do not reduce or alter the responsibility of licence holders under their Network Management Plans to assure delivery of a safe and reliable supply. Design Planning Criteria described in these conditions provide minimum standards for various categories of network elements.[48]

The licence conditions also expressly require all NSW DNSPs to compensate customers who suffer severe individual instances of poor performance, or ongoing poor performance. Schedule 5 of the NSW Distribution Reliability and Performance licence conditions (attached to EnergyAustralia's June 2008 proposal as Attachment 4.04) sets out the payments required to be paid to individual customers that suffer poor network performance outcomes.

[46] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008,, Vol 2, p38

[47] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Vol 2, p59

[48] NSW DNSP Distribution Reliability and Performance licence conditions.

3-6. Capital expenditure (continued)

EnergyAustralia prudently, and consistent with the interests of its customers, seeks to maintain satisfactory network reliability rather than compensate customers for poor performance.

There will be circumstances where network outages will exceed the level at which compensation under the Guaranteed Customer Service Standards (GCSS) will occur. EnergyAustralia has included the costs of addressing reliability issues in poorly performing parts of the network in its reliability blackspot program, and included an allowance for the costs of the (GCSS) payments under Schedule 5 of the licence conditions to compensate customers for circumstances where performance falls below the specified level.

The AER did not accept the GCSS payments forecast for the 2009-14 period. The AER has therefore neither allowed EnergyAustralia capital expenditure to address individual customer reliability issues, nor has it allowed EnergyAustralia the costs of compensating customers for poor performance.

This is not consistent with the capital expenditure objectives which expressly identify as an objective maintenance of the quality, reliability and security performance of standard control services. It is also inconsistent with the NSW licence conditions which contemplate investment plans outside the pure input requirements to meet reliability outcomes for customers.

Applying the Rules to the blackspot program

The AER's reasoning for rejecting the blackspot program appears to be that the blackspot program 'improves' rather than 'maintains' reliability and thus the program is not required to maintain quality, reliability and security of supply of standard control services or the reliability, safety and security of the distribution system.

This is both a semantic application of the capital expenditure objective, which is not consistent with the National Electricity Objective and the NEL Revenue and Pricing Principles, and is a misunderstanding of what has been proposed.

The blackspot program is a reactive rather than a proactive program and is thus not applied until customer performance falls below the specified threshold. It has therefore been characterised by EnergyAustralia as a program to 'improve reliability'. The expected outcomes of the program are to maintain the reliability of the network and reliability of standard control services above the blackspot threshold, by improving network performance when it falls below the threshold level.

At an individual customer level, reliability varies from year to year, due to issues such as weather, lightning activity and the impact of animals on outages. Given these external factors impacting customer reliability, it is difficult to accurately predict the supply reliability of each individual customer.

A proactive program to maintain performance above the threshold levels would in some cases target expenditure on parts of the network which would have remained compliant with the thresholds in the absence of remedial action. Such an approach, whilst falling within what appears to be the interpretation of the Rules taken by the AER, would require substantially greater expenditure and therefore less efficient than EnergyAustralia's proposed reactive program which will target known reliability problem areas.

EnergyAustralia does not believe it would be efficient to maintain the reliability of distribution services to individual customers using an expensive proactive program and has instead used a more efficient reactive program for this purpose.

EnergyAustralia is strongly of the view that addressing deterioration in the reliability of supply by bringing it back to an appropriate level (that is, improving reliability), is in fact maintaining the reliability of supply and is consistent with 'maintaining' the reliability of supply of both the distribution network and standard control services. EnergyAustralia submits the blackspot program is therefore consistent with the objectives under clause 6.5.7(a)(3)-(4) of the Rules and should be recognised in EnergyAustralia's capital forecast.

The alternative approach would result in unaccountable results. For example, if the reliability of supply to a customer fell below generally accepted levels of reliability of service, but did not result in an overall non-compliance with licence conditions, under the AER's approach, EnergyAustralia could not, consistent with the capital expenditure objective, incur capital expenditure to 'improve' that reliability level. The same reasoning would apply in relation to operating expenditure, as the same criterion applies under the operating expenditure objectives. This would simply result in a ratchetting down of reliability over time. The Rules and Law provide no textual or purposive support for such a conclusion. In fact, the Rules and the National Electricity Law are intended to achieve the opposite result - that is, a level of operating and capital expenditure that is in the long term interests of consumers of electricity.

We note the AER does not appear to have made a decision that EnergyAustralia should not undertake the blackspot investment, but has confined itself to issues of legal interpretation. The AER appears to suggest that EnergyAustralia should undertake the program regardless of its approval. This approach is not consistent with the Rules that require the business to recover the costs that a prudent operator in the circumstances would require to achieve the capital expenditure objectives.

3.6 Zone substation expenditure

The AER did not accept EnergyAustralia's cost estimates for the non-civil costs of zone and subtransmission substation construction. As a consequence, the AER has reduced zone substation and major substation expenditure by 3% of non-civil costs on the basis that it did not consider the substation costs used by EnergyAustralia to reasonably reflect the efficient costs of a prudent operator.

The AER's conclusion is based on its analysis of a report by SKM[49] comparing EnergyAustralia's cost estimates with those prepared independently by SKM. This was at Attachment 5.14 of the June 2008 regulatory proposal. The report found that non-civil costs were within 20% of EnergyAustralia costs, which SKM considered to be reasonable given the preliminary stage of development of the estimates.

The AER analysed SKM's report and found that on average SKM's estimated costs were 6% lower than EnergyAustralia's estimates. The AER identified a degree of uncertainty over the efficient level of costs by a prudent operator and reduced the non-civil component of zone substation costs by 3%.

[49] Attachment 5.14 to the June 2008 regulatory proposal (EA Substation Cost Estimate Review, SKM April 2008)

Wilson Cook findings

The AER engaged Wilson Cook to review the unit costs applied by each NSW DNSP. Wilson Cook found that the detailed comparison between providers sought by the AER was not possible because of differences between the DNSP's approaches. Despite the differences, Wilson Cook reviewed EnergyAustralia's unit costs, including the non-civil costs of substation construction.

Wilson Cook found that:

> On balance, given the methodologies used by EnergyAustralia, (Wilson Cook) accepted its (EnergyAustralia's) cost estimates as reasonable for the scope of the work concerned[50]

Wilson Cook stated that:

- EnergyAustralia's estimates are based on recent reported costs; and
- EnergyAustralia competitively tenders the majority (approximately 80%) of its capex.

EnergyAustralia's comments

EnergyAustralia does not accept the AER's findings and considers that they are based on an inadequate appreciation of the circumstances relating to the cost differences identified by SKM.

Energy Australia considers that the AER:

- has inappropriately applied benchmarking, which did not take account of the differences in EnergyAustralia's and SKM's cost estimates;
- overlooked expert advice and applied incorrect analysis; and
- has acted in a manner in regard to EnergyAustralia that is inconsistent with the manner applied to other NSW DNSPs being reviewed concurrently.

[50] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 2, p28.

3-6. Capital expenditure (continued)

Therefore, EnergyAustralia considers that the conclusion drawn from this analysis is based on error and has led to a decision to reduce EnergyAustralia's capital expenditure forecast that is unreasonable.

SKM's report

EnergyAustralia notes that benchmarking is one of the factors that the AER must take in to account when assessing its capital forecast.

The SKM report, which formed the basis for AER's reduction, was prepared by SKM at the request of EnergyAustralia to review costs for major substations.

SKM was asked to review and compare EnergyAustralia's estimates with its own SKM estimates and to carry out detailed analysis of any differences greater than 20%. This approach was appropriate because it allowed individual circumstances to be taken into account as required under transitional clause 6.5.7(c)(2). Specifically, the approach allowed SKM to understand the circumstances specific to EnergyAustralia that were driving differences between the two estimates.

SKM noted in its report that the projects assessed were in the preliminary study phase and as such they expected an order of accuracy in the estimates of between ±15% and ±25%. As EnergyAustralia's costs all fell within a range of 20% with SKM's own cost estimates, SKM concluded that with the exception of the civil costs, EnergyAustralia's substation costs appear to be reasonable. SKM did not consider a high-level review of civil estimates to be appropriate as civil costs are driven by site and manufacturer specific factors, and therefore not comparable with benchmark estimates.

In relation to non-civil costs, SKM concluded that EnergyAustralia's estimates were comparable and reasonable despite minor differences in the estimates.

EnergyAustralia did not receive questions from the AER regarding the minor differences between EnergyAustralia and SKM costs, and EnergyAustralia therefore did not provide any further explanation of the cost variations identified in the SKM report.

There are good reasons for considering that EnergyAustralia would be more likely to be able to accurately estimate its forecast capital expenditure, based on its experience on its own network, compared to SKM. There is simply no evidence to challenge the reasonableness of EnergyAustralia's forecasts.

The only expert opinion before the AER was that of SKM, which concluded that EnergyAustralia's forecasts were reasonable. However, the AER disregarded that evidence and concluded that, with the minor differences in cost estimates identified by SKM were significant. Accordingly, the AER reduced the proposed capital expenditure by $34 million to take account of these minor variances. The AER did not, consistent with its obligations under the Clause 6.12.1(3) of the Rules, provide reasons why the differences between the forecast cost warranted a reduction in the proposed capital expenditure, nor did it demonstrate how it had taken account of EnergyAustralia's particular circumstances.

There are a range of reasons why cost estimates may differ between EnergyAustralia's estimates and those of SKM including:

- allowing for costs of work in congested metropolitan areas;
- differences in wage rates between Sydney and other areas considered in SKM's benchmark costs;
- variation between costs of equipment arising from specific purchasing arrangements and timing (i.e. influenced by exchange rates, timing of contracts, and existing supply arrangements); and
- variations in equipment type or performance (i.e. equipment rating fault duty, transformer noise performance).[51]

Specific variations between EnergyAustralia and SKM costs were not addressed in the SKM review as the costs derived were regarded as equivalent within the accuracy of the estimates. AER ignored the purpose of the reported information and applied the findings incorrectly in their analysis, and mistakenly determined EnergyAustralia's capital expenditure as inefficient. It should be noted that the AER did not request clarification nor is there evidence that the AER

[51] For example, Parsons Brinkerhoff (PB) was engaged by Integral Energy to review high unit cost associated with low noise transformers. PB's review was included in Integral's regulatory proposal.

considered factors such as site specific issues which may account for the differences in costs.

EnergyAustralia has requested SKM to review the interpretation of its report by the AER. After reviewing the AERs finding SKM:

> considers that the AER's use of SKM's estimates was outside the scope for which the estimates were intended as the estimates were provided on an individual substation basis rather than for a suite of projects. [52]

Further:

> SKM do not consider that the methodology used by the AER in determining a reasonable and efficient level of capex by using SKM's individual substation estimates was appropriate[53]

In performing its analysis, the AER totalled the estimated EnergyAustralia costs and SKM costs for 20 different styles of substations and concluded that the difference in costs amounted to 6%. This averaging was applied to the sample of projects that were estimated which were representative of projects constructed. However, the AER did not consider the fact that EnergyAustralia's capital expenditure program is not comprised equally of the substation types considered. The simple averaging of the total estimates gives an inaccurate picture of the total cost of EnergyAustralia's zone substation program. When the results are weighted to account for the proposed numbers of different types of substations the difference falls to 3%.

Inconsistency in AER reasoning

There are a number of factors that indicate that the AER's decision to cut substation estimates on the basis of a sample of SKM planning estimates was not reasonable.

First, the AER's decision is not consistent with the views of several independent consultants. Wilson Cook, the AER's independent consultant, also considered EnergyAustralia's costs were reasonable for the scope of work concerned.[54]

Furthermore, PB, in reviewing the cost assumptions by Integral Energy during the preparation phase for this review, compared its estimates against other substation costs specified by Integral and other publicly available costs from EnergyAustralia and ETSA Utilities. PB concluded, on the basis of this comparison, that the forecast costs used by Integral in its proposal were reasonable.[55,56] EnergyAustralia costs used to support PB's review were actual project costs prepared on the same basis as EnergyAustralia's regulatory submission. This has lead to the incongruous result that EnergyAustralia's substation costs have in effect been relied on by the AER as a reasonable basis for approval of another business' forecasts, but have been rejected by the AER in EnergyAustralia's draft decision.

Secondly, the AER accepted that differences between consultant's reports and DNSP costs did not mean that DNSP costs were unreasonable for both Integral and Country Energy. AER has expressed the view in its draft decision that costs by other DNSP's were efficient based on information other than cost benchmarking. In particular:

- The AER accepted cost forecasts from other NSW DNSP's [57] on the basis that they were based on regularly updated estimating systems which were seen as capable of informing detailed bottom-up cost estimates.
- The AER accepted costs where it was claimed that they took account of most recent contract prices for equipment.

[52] SKM, *Considerations on AER review of EnergyAustralia's Substation cost estimation process*, 12 December 2008 (Attachment 3M)

[53] Considerations on AER review of EnergyAustralia's Substation cost estimation process. SKM 12 December 2008.

[54] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Vol 2, p28.

[55] Integral Energy's Appendix K to its June 2008 Regulatory proposal p 60.

[56] EnergyAustralia notes comments by PB summarised by AER in relation to future improvement in the level of detailed prescription used in Integral's estimates, and the fact that some estimates were seen to be on the high side of reasonable estimates, yet accepted by the AER.

[57] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p509 and p 433.

- The AER accepted Country Energy's costs as they were competitively tendered.[58]

The AER accepted these factors for Integral and Country Energy but did not extend the same reasoning to EnergyAustralia despite the fact that:

- EnergyAustralia's estimates are based on a robust, regularly updated estimating system;
- EnergyAustralia's estimates reflected most up to date contract prices available; and
- EnergyAustralia's civil and non-civil substation costs arise largely from competitively tendered materials and equipment.

The AER has accepted generic cost[59] estimates and broad claims of efficiency from other DNSPs but has reduced EnergyAustralia's expenditure using the more detailed analysis that EnergyAustralia itself provided to the AER as justification for the reasonableness of its estimates. EnergyAustralia appears to have been penalised for providing supporting evidence for its claims.

3.7 Equity raising costs

The AER in its draft determination considered that equity raising costs should be capitalised rather than treated as operational expenditure. EnergyAustralia has therefore included its estimate of equity raising cost as part of its total forecast capital expenditure and has responded to the matters raised by the AER in this capital expenditure chapter.

The AER reduced EnergyAustralia's proposed equity raising cost from $49 million to $36 million. The AER rejected EnergyAustralia's proposal to include indirect costs in the benchmark equity raising costs. The AER considers that no such compensation is required under the benchmark regulatory framework and that an efficient network service provider should be able to raise capital without incurring indirect cost.

[58] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p434

[59] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p509

The AER has also made some adjustments to the cash flow approach applied by EnergyAustralia to determine the benchmark equity raising costs. Of significance is the adjustment to the calculation of assumed dividend payments. EnergyAustralia in its June proposal applied a dividend yield of 8%, based on the advice of the Competition Economists Group (CEG). The AER rejected this and instead applied a dividend payout ratio of 70% in its draft determination.

EnergyAustralia's comments

EnergyAustralia does not accept the AER's decision to reject the indirect cost of equity raising. We see no reason to revise our response maintains our June 2008 proposal of including indirect equity raising cost.

We note the amendments made by the AER to the cash flow modelling; of significance is the use of a dividend payout ratio of 70% instead of a dividend yield of 8% as proposed in our June 2008 proposal.

EnergyAustralia considers that a dividend yield of 8% is sustainable as long as it is less than the return on equity. We note that a dividend payout ratio of 70% equates to a dividend yield of approximately 3%. If the AER chooses to apply a dividend payout of 70% in its determination, the economic value outcomes and assumptions in the PTRM must be consistent with this decision.

Our revised forecast equity raising cost also includes a cost for using internally generated funds of 3.8%. This is further discussed below.

Subsequent to the submission of our June 2008 proposal, the Energy Network Association (of which EnergyAustralia is a member), together with Grid Australia and the Australian Pipeline Industry Association (Joint Industry Association) provided to the AER on 11 November 2008 a submission on the cost of debt and equity raising. This submission reinforces our June 2008 proposal. The Joint Industry Association's (The JIA submission) submission can be found at attachment 3N.[60]

[60] Joint Industry Association, *Submission on debt and equity raising costs*, 11 November 2008 (Attachment 3N)

EnergyAustralia's response to the matters raised by the AER in its draft determination is supported by analysis contained in a report prepared by CEG who was engaged by EnergyAustralia, together with other NSW and Tasmanian businesses. This report is at attachment 3O (The CEG report).[61]

We have commissioned an additional independent appraisal of the AER's decisions with respect to the cost of raising equity. This appraisal finds that the conclusions drawn by the AER in the draft decision and the reasons relied upon by the AER for its decision is inconsistent with empirical results. This appraisal in the main also reinforces the arguments and analysis provided by CEG. This appraisal can be found at attachment 3.P (The Carlton report).[62]

Indirect equity raising cost

EnergyAustralia does not accept the AER's decision to reject indirect equity raising cost.

In its draft determination, the AER accepts that underpricing (i.e. an indirect cost of equity raising) can occur for both initial public offering and seasoned equity offerings.

The AER however considers that even if underpricing for equity raising does occur, compensation for such cost is not required because:

- it would be inconsistent with the benchmark regulatory framework applied to the calculation of the weighted average cost of capital (WACC); and
- the efficient benchmark network service provider should be able to raise equity without incurring underpricing cost.

The AER provided several reasons to support its conclusions above:

- In setting an allowance for the cost of equity raising, the AER assumes that it is regulating a hypothetical efficient benchmark firm. This efficient benchmark firm can undertake a seasoned equity offering using a rights issue. A rights issue, the AER asserted, is the most common practice of a seasoned equity offering. With a discounted rights issue, the existing shareholders benefit from the whole discount and there is no wealth transfer to new shareholders. Therefore, the AER considers that no compensation for underpricing is required.
- The AER asserts that an efficient benchmark firm should be able to raise capital by offering a given return which is the awarded WACC. This awarded WACC provides full compensation for investor risk that requires compensation under the CAPM and underpricing – an extra form of compensation for risk faced by new investors – is not required. Furthermore, the AER argued that an allowance for underpricing is inconsistent with CAPM which assumes all investors require the same rate of return, and hence implies that there should be no allowance for underpricing for new investment.
- The AER consider that the cost of raising equity requires a downward adjustment. This downward adjustment to the direct costs of underwriting. This downward adjustment is for the value of the put option embedded in the underwriting fee. The AER argued, therefore, the direct cost of equity raising should be reduced by fair value of the put option component of the underwriting fee.

Rights issue is not the most common form of season equity offerings.

In its reasoning, the AER asserted that rights issue is the most common form of seasoned equity offering. The AER also acknowledged that firms, using a rights issue, can offer shares at a discount.

If such reasoning by the AER is correct, then one would expect discounted rights issue as the most common, if not sole, source of equity raising. With a heavily discounted rights issue,

[61] CEG: *Debt and equity raising cost, a response to the AER 2008 draft decisions for electricity distribution and transmission*, January 2009 (Attachment 3O)

[62] Carlton, Indirect costs of equity and debt raising for EnergyAustralia, January 2009. (Attachment (3P)

firms can maximise the chances of shareholder take up and ensure the success of the raising capital.[63].

However, the assertion by the AER that rights issue is the most common practice for seasoned equity offerings is not supported by empirical data. The most common form of equity raising in Australia is via the use of placement (by absolute dollar value or by the number of issues) [64].

Data on seasoned equity offerings in Australia since 1991 provides evidence that placements have been the largest source of equity raising measured by absolute dollar value in Australia. Data on seasoned equity offerings in Australia from July 1996 to March 2001 demonstrates that placements have been the largest source of equity raising measured by number of issues in Australia.

In a study of equity raising via rights issue and placements for the period from July 1996 to March 2001, Chan and Brown found that 85% of the number of equity issues was via placements with the balance being rights issue.[65] The result of this study is presented in table 2 of the Carlton report.

Table 1 of the Carlton report presents data on seasoned equity offerings in Australia. This data demonstrates that placements have been the largest source of equity, raising significantly more capital than rights issue. For example, this data reveals that for the years 2007 and 2008, placements have been used to raise nearly more than double the amount of capital raised by rights issues.[66]

This empirical data for Australia is typical of other developed capital markets. Table 3 of attachment 3P shows the details of equity raising in the US for the period 1980 – 2008 for industrial and utilities companies. Specifically, the data revealed that:

- utilities in the United States have used placements to raise 170 times more equity than that raised by rights issues; and
- rights issue made up less than 1% of all seasoned equity offerings by utilities in the United States.

The evidence also suggests that most rights issues are undertaken to conform with ASX listing requirements that put a ceiling on placements of 15% in any twelve month period. In this case the use of a rights issue is not necessarily evidence that it is the lowest cost method[67].

This data is inconsistent with the AER's assumption that rights issue is the most common practice for seasoned equity offerings. The Carlton report notes that[68]:

> the current market conditions will only accelerate the use of this equity raising technique (i.e. placement) because of its ability to achieve certainty in a very volatile environment.

Discounting/underpricing is a true cost

The AER, on the assumption and reasoning that rights issue is the most common form of seasoned equity offerings, concluded that there is no wealth transfer in a rights issue as the existing shareholders accrue all the benefits of the underpricing. Hence the AER concluded that no compensation for underpricing is required.

The Carlton report demonstrates empirically that placement is commonly used to raise equity. This is contrary to the AER's view. Even if a firm raise equity entirely by way of a rights issue (a proposition not supported by empirical evidence), it would be incorrect for the AER to conclude that there is no wealth transfer from a rights issue. The evidence demonstrates clearly that firms should be compensated for underpricing as it is a legitimate cost of raising equity.

EnergyAustralia submits that in light of the empirical data, it is not reasonable to assume that rights issue is the most common practice of seasoned equity offerings nor is it

[63] CEG, *Debt and equity raising costs – A response to the AER 2008 draft decisions for electricity distribution and transmission*, January 2009, paragraph 42.
[64] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia*, section 1.1.1.
[65] Carlton, "Indirect costs of equity and debt raising: report prepared for EnergyAustralia", table 2.
[66] Carlton, "Indirect costs of equity and debt raising: report prepared for EnergyAustralia", table 1.
[67] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia*, pages 2-7,11
[68] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia*, page 6.

reasonable to assume that the full amount of equity required can be raised via rights issue alone. This is because:

- There is no certainty that all existing shareholders will subscribe to the rights issue (i.e. that there is a full take up of rights offered). Existing shareholders can be capital constrained and may not have sufficient funds to take up the rights issue. Even if the shareholders sell their existing shares to fund their participation in the rights issue, they would still incur transaction costs.
- By increasing their share in a company, existing shareholders lose the benefit of diversification, and therefore may not wish to invest further in a company.

In contrast, equity raising via placement is a speedy method of equity raising that provides certainty to issuing companies as well as other benefits.[69]

With the use of placement as the predominant means of equity raising, there is a wealth transfer from existing equity shareholders to new shareholders. That is, there is a dilution of the values of existing shares when equity raising occurs via placement. Appendix 3 of the Carlton report provides a simple illustration of the wealth transfer effect of equity raising via placements.

In light of the evidence and analysis provided in the Carlton and CEG reports, EnergyAustralia considers the AER must revise its conclusions in regard to the indirect costs of equity raising, and change its assumptions that equity raising is undertaken primarily through rights issues and that no compensation for underpricing is required.

Rights issue do involve costs

The AER states that rights issues involve no costs to existing shareholders as they can usually sell their rights (as the rights are normally tradeable/renounceable) if they do not wish to further invest in the firm or sell their existing shares to take up the rights.

On the basis of independent expert advice provided by CEG and Carlton's reports, EnergyAustralia considers that there is in fact a dilution of existing shareholders wealth when a rights issue occurs. If the right is non tradeable (non – renounceable), then the non-participating shareholders will have the values of their shares diluted by the fact that the firm is selling discounted shares to those existing shareholders who do participate.

A non-tradeable/non-renounceable rights issue often forces the shareholders to subscribe (if they want to avoid dilution) and then sell a portion of their share holding to maintain their desired level of investment; consequently incurring transaction and tax costs.

The Carlton report unequivocally states that[70]:

> For a non renounceable offering shareholders do not receive any benefit from the discount unless they subscribe to the issue. Failure to subscribe means that they do not receive any benefit, and therefore will suffer a dilution in their value, in the same manner as under a placement.

This view is consistent and in fact reinforces the view expressed in the CEG report that a non tradeable rights issue is akin to a "gun to the head" of existing shareholders.[71]

Further, EnergyAustralia contends that where rights are tradeable, there is still a cost to existing shareholders. This is contrary to the view asserted by the AER. The AER argues that if a shareholder chooses not to participate in a rights issue, that shareholder can sell their right. However, this assumption requires the existing shareholder to bear the transaction costs of selling the rights. The sale of these rights is also taxable as capital gain[72].

The Carlton report states that evidence from Australian markets show negative reactions to announcement of large discounts in rights issues. Firms offering large discounts in their rights

[69] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia*, section 1.1.4 summarises some of the benefits of raising equity via placement.

[70] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia*, January 2009, page 8

[71] CEG, *Debt and equity raising costs – A response to the AER 2008 draft decisions for electricity distribution and transmission*, January 2009, paragraph 40.

[72] Section 1.1.3 of attachment 3P summaries the costs of a rights issue.

issues suffered a decline in total market value of 4% on average. This decline of 4% is approximately equivalent to 8% of the issue proceeds. A decline of 4% in market value is economically significant[73].

The results and analysis presented in both the Carlton and CEG reports contradict the assertion made by the AER that rights issues involve no costs to the firm or its existing shareholders.

Underpricing is not inconsistent with CAPM

The AER argued that the awarded WACC provides full compensation for investor risks and that no further compensation, in the form of underpricing, is required.

This view by the AER, if it were true, implies that:

- all firms can raise equity using a non underwritten rights issue with zero discount; and
- there is no market response to announcements of equity raising as the investors are fully compensated by the returns specified by CAPM.

In reality, the outcome of equity raising is very different to the AER's theoretical view. The Carlton report demonstrates empirical studies of seasoned equity offerings which found that underpricing does occur in equity issues, and contrary to the prediction of the AER, firms do not raise equity with zero discounts. A study by Balachandran, Faff and Theobald found that the average discount for rights issue in Australia was 20%.[74]

In a recent article on alternative equity raising options, J. Draho argued that:

> the conventional measure for the expected return is determined using the CAPM model, in which only a stock's systematic risk matters for the return… But this is only a starting point for the analysis… on top of and separate from these measurement problems, the cost of raising equity involves more than just investors required returns for bearing systematic risk. If that was all that mattered, most companies would be able to sell their share at current share price. Yet new shares are generally sold at significant discounts to the companies' pre-announcement prices. The result is a dilution in the value of existing shareholder claims, a cost that increases with the size of the stock offering[75]

Empirical evidence shows that there is typically a negative market response to announcements of equity raising. Balachandran, Faff and Theobald found a negative market response of -1.74% for rights issues in Australia[76]. A range of non zero market responses also occurs for seasoned equity issues in the United States.[77]

Recognition of underpricing cost does not imply a rejection of CAPM. The CAPM does not attempt to recognise the transaction costs and frictions in issuing new securities. [78]Underpricing fulfils an important economic role, over and above underwriting. Underpricing serves the role of providing an incentive to investors who provide liquidity, bear risk and provide information as part of the issuing process. It is an important part of marketing and promoting the issuing company.[79]

The AER failed to recognise the value of a call option

The AER has correctly recognised that an underwriting contract results in the regulated firm receiving a put option. This put option is the ability of the regulated firm to sell the shares to the underwriter at a higher price than the market value of those shares. That is, the benefit received by a regulated firm from

[73] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia*, page 7.

[74] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia* , page 16..

[75] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia* page 15.

[76] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia*, page 16.

[77] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia* , page 16.

[78] CEG, *Debt and equity raising costs – A response to the AER 2008 draft decisions for electricity distribution and transmission*, section 2.3.

[79] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia*, section 1.2. Also CEG, *Debt and equity raising costs – A response to the AER 2008 draft decisions for electricity distribution and transmission,* section 2.3.

overpricing a share issue should be offset against the underwriting fee paid.

However, the AER has not properly considered the opposite scenario, that is, an underwriting contract also results in the regulated firm giving the underwriter a call option[80]. This call option is the ability of the underwriter to buy the shares at a price lower than their market value, (i.e. the shares have been underpriced). This underpricing is therefore a cost, and in the situation where underpricing occurs, the total cost of equity raising incurred by a regulated firm is both the direct underwriting fee and the indirect underpricing cost.

Indirect cost meets the operating or capital expenditure objectives

Empirical evidence shows that the most common form of equity raising is by placement. The total cost of equity raising via placement is the underwriting cost and underpricing costs required to entice new shareholders. Discounts on placements (i.e. the indirect costs) are legitimate costs to the business.

The Carlton report demonstrates that placement do result in the transfer of wealth from existing to new shareholders. This cost approximates the size of the discount. The report states that[81]:

> The main indirect cost of a placement, or any other equity raising targeted at investors other than existing shareholders, is the discount offered relative to the market price… Placement do result in a transfer of wealth from existing equity holders to new equity holders, roughly equivalent to the size of the discount.

However more importantly, both the CEG report and the Carlton report demonstrate that irrespective of the method used (i.e. rights issue or placement) there are costs involved. Raising equity via a rights issue does not "assume" away costs incurred by existing shareholders as the AER has contended.

Attachment 8.2 of our June 2008 proposal, the JIA submission, the CEG report and the Carlton report all support a finding that underpricing is an important element of an efficient capital raising strategy. Underpricing, therefore, is a cost that meets the capital and operating expenditure criteria. In particular, underpricing is a prudent and efficient cost that a DNSP would incur to achieve the capital and operating expenditure objectives.

EnergyAustralia considers that the AER should review its decision with respect to indirect equity raising cost in its final determination.

Cash flow modelling

In order to determine if compensation for the cost of raising equity is required, cash flow modelling is applied to determine if there is insufficient internal cash flow to fund the equity portion of forecast capital expenditure.

The AER, in its draft determination, has made several amendments to the cash flow modelling undertaken by EnergyAustralia. Of note is the adjustment to the calculation of dividend.

In the cash flow modelling for EnergyAustralia's June 2008 proposal, EnergyAustralia applied a dividend yield of 8%. In its draft determination, the AER instead applied a dividend payout ratio of 70% which it considers is consistent with a gamma of 0.5 assumed in the Rules. The AER considered that a dividend yield of 8% resulted in an unsustainable payout ratio of well over 100% of "accounting" net profit after tax.

EnergyAustralia considers, however, that a dividend yield policy of 8% is sustainable as long as it is less than the estimated cost of equity. The return to equity holders must equal the cost of equity in the long run.

In its draft determination, the AER calculated a nominal post tax return on equity for EnergyAustralia of 11.34%. Our revised cost of capital (chapter 8) results in a nominal post tax return on equity of 11.82%.

EnergyAustralia notes that the application of the AER's cash flow modelling with a dividend payout ratio of 70%, based on our revised PTRM, equates to a dividend yield of approximately

[80] CEG, *Debt and equity raising costs – A response to the AER 2008 draft decisions for electricity distribution and transmission*, section 2.2

[81] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia*, page 12

3-6. Capital expenditure (continued)

2.7%[82]. This dividend yield is significantly below the return on equity that an equity investor would expect.

EnergyAustralia considers that if the AER chooses to apply a dividend payout policy in its determination, the AER must be consistent in its decision regarding dividend payout policy and the economic value outcomes and timing assumptions of the PTRM.

As a general principle, if the AER provides for lower than expected dividends in response to high capital expenditure, there must necessarily be periods of higher than expected dividends to achieve the long term average returns to equity holders.[83]

We understand that Integral Energy is providing further details in its response to the AER's draft determination on this issue. Insofar as Integral Energy's submission relates to cash flow modelling and the application of the dividend payout ratio, EnergyAustralia incorporates that part of Integral Energy's submission in this submission. We may also provide further submissions on this issue in response to the AER's draft determination.

In the calculation of equity raising costs for this revised proposal, EnergyAustralia has applied the AER's cash flow modelling with an amendment to incorporate an additional cash outflow.

Specifically, this modification takes account of the fact that in order to maintain the benchmark gearing assumption of 60%, the cash flow modelling must allow for a cash outflow to reflect the repayment of the principal on existing debt. This repayment equates to 60% of the regulatory depreciation.

[82] This is the average of the annual effective dividend yield for the regulatory period 2009 to 2014. The effective annual dividend yield is calculated by dividing the dividend amount by the equity component of the mid-point RAB value. The calculation is contained in the file "14 Jan 2009 EnergyAustralia (confidential)(master)-ERC.xls" submitted with this revised proposal.

[83] CEG, *Debt and equity raising costs – A response to the AER 2008 draft decisions for electricity distribution and transmission*, section 3.2.

This cash outflow to repay principle is not taken into account in the AER's cash flow modelling used in its draft determination. EnergyAustralia wrote to the AER on 29 October 2008 advising of the required modification to the current method of cash flow modelling. Details of this amendment were provided in the JIA submission to the AER and are also included in the CEG report.

The cost of using internally generated funds

The JIA submission and the CEG report also identified that use of internally generated cash flows (i.e. retained earnings) is not costless and that there is a point at which internal funding is more costly than external funding. The first dollar of internally generated funds would have a cost of 0% and the last dollar would have the same cost as a seasoned equity offering. EnergyAustralia has applied a unit cost of 3.8%, being a simple average of the cost of the first dollar of internally generated funds of 0% and the 7.6% cost of the last dollar. This unit cost of 3.8% is applied to the amount of internal funds used to finance the equity component of forecast capital expenditure that expands the earning potential of the network relative to the earnings potential at the start of each year.

Further details and discussion of this issue can be found in the JIA submission.

EnergyAustralia has revised its forecast of equity raising cost to:

- Incorporate modification to the cash flow modelling to account for the principal repayment of debt.
- Incorporate the cost of internally generated funds at 3.8%.

EnergyAustralia maintains its June 2008 method of calculating equity raising costs in all other respects which incorporates:

- indirect cost of raising equity; and
- the use of 7.6% as the cost of seasoned equity offering – the estimate of both direct and indirect equity raising costs.

EnergyAustralia has revised its forecast of capital expenditure requirements to include the revised forecast of equity raising costs. The revised equity raising costs is to address the matters raised by the AER concerning the cash flow modelling and the AER's preferred treatment of equity raising costs as forecast capital expenditure. This results in a $179 million increase in the forecast of capital expenditure.

3.8 Revised capital program

EnergyAustralia has revised its capital program (see Table 3.6) to account for the following factors:

- Reductions in capacity related expenditure arising from updated peak demand forecasts (Section 3.1 and 3.2)
- Adjustment to expenditure on feeders 908 & 909
- Revised cost escalators (Section 3.4)
- Remove impact of tariff based DM (section 3.3)
- Transfer of equity raising costs from operational expenditure

Table 3.6 EnergyAustralia's revised capital expenditure forecast 2009-2014 ($2008-09 million real)

	2010-14	FY10	FY11	FY12	FY13	FY14
June 2008 proposal	8659	1583	1603	1878	1830	1763
908-909 Adjustment	-8	-6	-1	0	0	0
Escalation Adjustments[84]	-145	0	-8	-33	-39	-65
Adjustment [85] for Forecast	-234	-13	-15	-86	-35	-84
Tariff DM	31	0	0	0	0	31
Equity Raising	179	179				
Revised proposal	**8482**	**1743**	**1579**	**1758**	**1756**	**1645**

Deliverability of capital expenditure program

The ability of DNSPs (including EnergyAustralia) to deliver their proposed capital program was raised in stakeholder submissions and during the AER's public forum held on 9 December 2008.

EnergyAustralia recognised in its June 2008 Regulatory Proposal that it was necessary to modify its capital program to ensure deliverability[86] and also recognised that a suite of delivery strategies[87] was required to deliver the required outcomes. These strategies have provided a deliverable investment program.

In its report on EnergyAustralia's Regulatory proposal, Wilson Cook found 'EnergyAustralia has recognised the need to increase its resources to deliver its proposed investment programme and has taken measures to ensure that it is able to

[84] Includes corrections of errors in application of escalators.
[85] Includes, Area plans, 11kV development plan, LV Plan and other expenditure.
[86] EnergyAustralia Regulatory Proposal June 2008, p 74.
[87] EnergyAustralia Regulatory Proposal June 2008, p 75.

do so.' [88] Further, Wilson Cook concluded that EnergyAustralia had proposed a reasonable implementation strategy and that they had 'no reason to suppose that EnergyAustralia will be unable to carry out its proposed program'.[89]

The AER also reviewed matters relating to the deliverability of EnergyAustralia's proposed capital forecast and was satisfied that the deliverability of the forecast capital expenditure program will not be constrained by resource availability. It noted that physical resource constraints were likely to be addressed to some extent by the present economic circumstances which will see a reduction in the demand for skilled resources from other sectors of the economy.

The AER concluded that EnergyAustralia's plans to deliver its program were robust and that the deliverability of the forecast capital expenditure program is consistent with the capital expenditure objectives.[90]

Since EnergyAustralia's June 2008 proposal, changing circumstances have further improved the deliverability of the capital expenditure program. Specifically:

- economic conditions are expected to reduce the pressure on resources (as noted by the AER); and
- the level of capital expenditure has been reduced as a result of deferral of demand driven projects discussed in section 3.2.

Whilst EnergyAustralia is cognisant of the concerns expressed at the Public Forum regarding the deliverability of its program, EnergyAustralia considered in June 2008 that it had presented a realistically deliverable program. This was confirmed by both the AER and its consultants Wilson Cook. Events since June 2008 have further increased EnergyAustralia's confidence that the forecast capital program will be delivered.

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[88] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 2, p 40

[89] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 2, p66.

[90] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p498

7. Depreciation

REVISED PROPOSAL

EnergyAustralia has revised its regulatory depreciation for the 2009-14 regulatory control period.

The revision to EnergyAustralia's regulatory depreciation is to respond to the matters raised by the AER. Specifically, this revision is to:

- correct for an input error relating to the standard life for cable tunnel (dx) asset. This error was identified by the AER; and
- reflect certain consequential changes, noted below.

Regulatory depreciation is an output of the post tax revenue model. Consequently, revisions to inputs into the post tax revenue model would result in revision to the regulatory depreciation.

In its draft decision, the AER notes that "regulatory depreciation has been calculated by the PTRM on the basis of each DNSP's proposed remaining and standard asset life inputs, and the opening RAB…. and forecast capex values"[91].

EnergyAustralia's revised regulatory depreciation therefore incorporates revisions made in this response that have a consequential impact on the calculation of regulatory depreciation. These relevant revisions are:

- to the opening RAB (chapter 2) and resulting revision to the remaining life of the opening RAB assets (section 7.1 below).
- to forecast capital expenditure for the 2009-14 regulatory period (chapters 3-6).

No amendments have been made to the methods or approach to the derivation of regulatory depreciation.

This chapter (including the attached revised depreciation schedules) together with Chapter 7 (including Attachment 7.2) of the June 2008 regulatory proposal is now EnergyAustralia's current proposal in relation to Depreciation. EnergyAustralia notes that Table 7.1 in the June 2008 proposal has been substituted by Table 7.2 in this revised proposal.

Rule requirements

The AER's draft determination is predicated on a decision on whether or not to approve the depreciation schedules submitted by EnergyAustralia. If the AER decides against approving them, the AER then must make a decision determining the depreciation schedules in accordance with clause 6.5.5(b). (Clause 6.12.1.(8))

Our June 2008 building block proposal

In its June 2008 proposal, EnergyAustralia:

- submitted depreciation schedules as required by Schedule 6.1.3(12) of the Rules.
- proposed an allowance for regulatory depreciation for each regulatory year totalling $609 million ($ nominal) for the 2009-14 regulatory period.
- proposed the addition of four new asset classes with corresponding standard lives.

AER's draft determination

The AER decided not to approve the depreciation schedules submitted by EnergyAustralia because of an error in the standard life for cable tunnel (dx). The AER:

- corrected the standard life of cable tunnels (dx);
- accepted the standard lives of other asset classes;
- considered that the proposed standard lives of the four new asset classes to be reasonable; and
- reviewed and found that the remaining lives of the opening RAB assets have been appropriately rolled forward.

On the basis of approved (and corrected) asset lives, opening RAB and forecast capital expenditure allowance, the AER has determined a regulatory depreciation allowance for each regulatory year of the 2009-14 regulatory period totalling $600 million ($ nominal).

[91] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p213

7. Depreciation (continued)

Our response to the AER's draft determination

EnergyAustralia accepts the AER's findings with respect to:

- the standard lives of existing and new asset classes;
- the roll forward of the remaining lives of the opening RAB assets; and
- the correction required to the standard life for cable tunnel (dx).

Based on the approved standard lives, updated remaining lives and revisions in other parts of our response, EnergyAustralia's revised remaining asset lives and revised allowance for depreciation are shown respectively in tables 7.1 and 7.2.

The depreciation schedules required by Sch 6.1.3(12) is at attachment 7A.

7.1 Revised remaining lives of opening RAB assets

As noted in chapter 7 of our June 2008 proposal, the remaining asset lives are established by rolling forward the 2004 opening asset values, adjusted for net capital expenditure and depreciation to 1 July 2009.

The revision to EnergyAustralia's opening RAB to reflect actual net capital expenditure for 2008 FY therefore impacts on the remaining lives of opening RAB assets. These revised remaining lives, based on the same calculation method, are shown in table 7.1 below.

Table 7.1 EnergyAustralia's revised remaining asset lives (years)

Asset class	Revised remaining lives
Transmission & zone land & easement	n/a
Transmission building 132/66 kV	40.4
Zone building 132/66 kV	45.9
Transmission transformers 132/66 kV	34.2
Zone transformers 132/66 kV	32.9
Transmission substation equipment 132/66 kV	28.5
Zone substation equipment 132/66 kV	31.5
Transmission and zone emergency spares	40.0
Ancillary substation equipment (tx)	n/a
132 tower lines	24.1
132 kv concrete and steel pole lines	43.6
132 kv wood pole lines	28.9
132 feeders underground	24.4
Cable tunnel (tx)	64.6
Network control & com systems	21.2
Communications (digital) (tx)	n/a
System IT (tx)	n/a
Sub-transmission lines and cables	27.8
Cable tunnel (dx)	69.5
Distribution lines and cables	45.9
Substations	32.2
Transformers	27.4
Ancillary substation equipment (dx)	n/a
Low voltage lines and cables	34.7
Customer metering and load control	19.5
Customer metering (digital)	n/a
Communications	8.0
Communications (digital) - dx	n/a
Land and easements	n/a
System IT (dx)	n/a
Emergency spares (major plant, excludes inventory	n/a
IT systems	4.2
Furniture, fitting, plant and equipment	13.9
Motor vehicles	8.4
Buildings	33.0
Land (non system)	n/a
Other non system assets	12.0

7.2 EnergyAustralia's revised regulatory depreciation

The table below shows the revised regulatory depreciation for the 2009-14 regulatory control period.

Table 7.2 Depreciation building block (FY09 $m real)

	FY10	FY11	FY12	FY13	FY14
Depreciation	282	342	394	448	473

8. Rate of return

REVISED PROPOSAL

EnergyAustralia has revised its proposal to include updated values for the nominal risk free rate and debt risk premium based on a revised proposed averaging period of 15 business days commencing 18 August 2008. We note that the June 2008 regulatory proposal included indicative values for the nominal risk free rate and debt risk premium as the averaging period had not passed. The revised agreed period results in a proposed rate of return of 10.15 per cent.

EnergyAustralia has also revised its proposal in respect of the calculation of the debt risk premium to reflect a similar averaging period and correct for problems in underlying data caused by lack of liquidity in the corporate bond market.

EnergyAustralia has revised its proposed averaging period to address the AER's reasons for the rejection of its original proposed averaging period.

The essential premise of the AER's initial decision to reject EnergyAustralia's proposal and to select a later period was, in effect, that CAPM theory suggests the most proximate date for the averaging period provides the best information for an unbiased estimate of the rate of return.

EnergyAustralia considers that this premise is unsound as has become apparent from subsequent events, namely the global financial crisis. The available evidence is that an averaging period affected by the current abnormal financial market conditions will provide an estimate of the rate of return under the Rules which is materially biased below the rate of return required by investors in a similar commercial business.

Accordingly, EnergyAustralia considers that the AER's decision not to accept EnergyAustralia's original proposed 'averaging period' and to specify an alternative period was incorrect. We consider our original proposed averaging period represented reasonable and prudent debt and risk management practice and was consistent with Rule requirements.

We note the AER considered EnergyAustralia's proposal in July 2008, before the implications of the global financial crisis on financial markets and the rate of return were apparent.

The AER's specified averaging period for observing key financial data is highly likely to include data that has been impacted by this supervening critical event. Expert financial evidence demonstrates that using this period will lead to an estimate of the rate of return which is materially below that required by investors.

Accordingly, the essential premise on which the AER withheld agreement to EnergyAustralia's original proposed averaging period, noted above, must now be rejected.

Furthermore, to maintain an averaging period in a period affected by the current market conditions, will result in an outcome contrary to the Rules, including clause 6.5.2(b), and the revenue and pricing principles in the Law.

Notwithstanding that EnergyAustralia considers the AER was wrong to reject its initial proposed averaging period, we have revised our proposal to take into account the most up to date information on financial markets and its impact on setting a rate of return required under the Rules, excluding the period affected by the current global financial crisis..

Our revised averaging period addresses the AER's reasons set out in its draft determination for not accepting EnergyAustralia's original proposed period. The revised period of 15 days commencing 18 August 2008 is the period closest to the regulatory control period prior to the emergence of the marked acceleration of the global financial crisis in September 2008.

Our revised proposal also includes an alternative approach to calculating the debt risk premium to reflect the most up to date information. EnergyAustralia has received evidence to suggest the approach originally proposed (and accepted by the AER) does not result in a reasonable calculation of corporate bond yields.

Using our revised averaging period and estimation of corporate bond observations over that period, EnergyAustralia's revised rate of return is 10.15%.

To be clear, this chapter including Attachment 8A together with Chapter 8 of the June 2008 proposal comprise EnergyAustralia's current proposal in relation to the rate of return (Note that sections 8.2 and 8.3 and Attachment 8.1 of the June 2008 proposal are relevant to understanding EnergyAustralia current proposal, but now must be considered subject to the material in this chapter).

Part I – Building block proposal

Rule requirements

The AER's draft determination is predicated on a decision in relation to the rate of return in accordance with clause 6.5.2 of the Transitional Rules. (Clause 6.12.1(5)).

Our June 2008 building block proposal

EnergyAustralia calculated a post tax nominal WACC of 9.80 percent. This was calculated:

- utilising the deemed parameters specified in the Transitional Rules;
- using the calculations and parameters prescribed in the Transitional Rules and predefined in the PTRM; and
- using market parameters consistent with those observed by the AER in previous regulatory decisions.

We noted that actual market parameters will be used to calculate the value of WACC in the AER's determination. We advised the AER of the observation period for those parameters.

AER's draft determination

The AER decided that the rate of return to apply to EnergyAustralia is 9.72 percent based on the Rule requirements and applying the parameters and values outlined in its draft determination.

- The AER specified a period to estimate the risk free rate, which was closer to the final determination date compared to EnergyAustralia's proposed period.
- The AER considered that the debt risk premium should be determined with reference to the same averaging period that was adopted for determining the risk free rate.

For the purposes of its draft determination, the AER used the 15 day moving average for Commonwealth Government Security ("CGS") yields with a ten year maturity period ending on 17 October 2008 to give a proxy for the nominal risk free rate. The debt risk period was based on the same period for Bloomberg estimates of the fair value of corporate bonds (which the AER used to estimate a 10 year BBB+ fair value yield noting that Bloomberg does not estimate this itself). The AER noted that its final determination will incorporate the nominal risk free rate and debt risk premium based on the AER's specified averaging period.

Our response to the AER's draft determination

EnergyAustralia does not accept the AER's decision on rate of return.

- Section 8.1 provides background to the averaging period used for calculating the nominal risk free rate and debt risk premium.
- Section 8.2 outlines the AER's decision to withhold agreement to EnergyAustralia's proposed averaging period and provides evidence as to why this decision is incorrect.
- Section 8.3 outlines the AER's substituted averaging period.
- Section 8.4 explains the current global financial conditions and provides evidence as to why these conditions are important in considering an appropriate averaging period.
- Section 8.5 details why, in the context of current global financial conditions, the AER's proposed averaging period is demonstrably inappropriate for a decision on the rate of return required by investors.
- Section 8.6 outlines EnergyAustralia's revised averaging period for determining the nominal risk free rate and debt risk premium.
- Section 8.7 notes adjustments that the AER must make if it does not agree with EnergyAustralia's revised proposed averaging period.
- Section 8.8 provides evidence supporting a revised calculation of the debt risk premium, given traditional methods of calculation appear to be distorted by the supervening critical financial event
- Section 8.9 updates the indicative WACC in EnergyAustralia's proposed post tax nominal WACC to reflect the WACC from EnergyAustralia's revised averaging period.

8.1 The AER's selection of an appropriate averaging period to establish the risk free rate

The AER's decision making framework and its relevance to decisions on the appropriate averaging period

The Transitional Rules require EnergyAustralia's rate of return to be applied to the value of the regulatory asset base at the beginning of each regulatory year. The rate of return applicable for each regulatory year of a regulatory control period is:

> … the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the distribution business of the provider…[92]

The rate of return provides a key incentive for attracting investment in regulated networks.

A rate of return set below that required by investors, will provide no positive incentive for those investors to invest. Rather, investment will tend to be deferred (inefficiently) until the rate of return is sufficient to encourage and reward investment.

The AER must consider whether the overall rate of return is consistent with the National Electricity Objective (NEO) and the Revenue and Pricing Principles in the NEL. In particular, in making its decision on rate of return the AER must have regard to the broader objectives of:

- promoting efficient investment outcomes;[93]
- providing EnergyAustralia with a reasonable opportunity to recover at least its efficient costs.[94]

The AER, in its explanatory statement on the review of WACC parameters explicitly recognises that the guiding principle in considering the various values and methods for individual WACC parameters is whether the overall rate of return derived is consistent with the NEL Objective. In particular, the AER stated:

> Of particular relevance in relation to the rate of return, is that the WACC be set at a level sufficient to induce the efficient investment in electricity network infrastructure, while not set too high so as to induce the inefficient overinvestment in electricity network infrastructure. The AER considers that if it determines values and methods for individual WACC parameters that produce an overall regulatory rate of return that is expected to achieve this outcome, then the AER will have exercised its power in a manner that will or is likely to contribute to the achievement of the National Electricity Objective.[95]

The AER is required to make its decision on a case-by-case basis, taking into account relevant aspects of the market environment and conditions that shape the return required by investors. This requirement is particularly important given the current market conditions and its impact on setting an appropriate rate of return.

The importance of the risk free rate in setting an appropriate rate of return

As most parameters for the rate of return are prescribed in clause 6.5.2 of the Transitional Rules, the AER's role in deciding on an appropriate nominal rate of return is limited to a decision about the nominal risk free rate under clause 6.5.2(c) and a decision about the debt risk premium under clause 6.5.2(e).

In addition, we note that the AER is also required, under clause 6.4.2(b)(1) of the Transitional Rules, to include in the post-tax revenue model a method that is likely to result in the best estimates of expected inflation. The estimates of expected inflation in the PTRM determine the real return for the distribution business.

These are the only parameters in relation to the rate of return for EnergyAustralia which are not "locked" in by the Rules and therefore the only values where the AER is required make a decision which ensures the rate of return is consistent with the requirements in the Rules and the NEL.

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[92] Clause 6.5.2(b) of the Transitional Rules
[93] Sections 7 and 7A(3) of the NEL
[94] Section 7A(2) of the NEL

[95] AER, *Explanatory Statement – Predetermination of review of WACC parameters*, December 2008, p39

The AER's draft determination states that the nominal risk free rate is the rate of return an investor would expect from an asset with zero volatility and zero default risk[96]. The yield on long term Commonwealth Government bonds are often used as a proxy for the risk free rate because the risk of government default on interest and debt repayments is considered to be low.

The risk free rate is an important parameter in the calculation of the weighted average cost of capital as it informs both the cost of debt and cost of equity.

CEG, in a report (2009 CEG report) prepared for EnergyAustralia and other network service providers (and set out at Attachment 8B) on the averaging period notes the importance of the risk free rate in estimating the cost of equity:

> The cost of equity formula is derived from the Capital Asset Pricing Model (CAPM) which is a finance theory that predicts investors will require a return in risky assets that is equal to the risk free rate plus a measure of the risk of an asset relative to the average risk of the diversified market portfolio (beta) multiplied by the risk premium investors require for investment in the market portfolio (the "market risk premium", or "MRP").[97]

The calculation of the cost of debt is determined by market observations of the corporate bond rate which implicitly includes a premium on the risk free rate. The difference between the yields on corporate bonds with a BBB+ rating and the annualised yield of Commonwealth Government bonds is used as a proxy for the debt risk premium. This is then added to the risk free rate to estimate the cost of debt – with the effect that the level of the risk free rate cancels out and the cost of debt is simply equal to the observed cost of BBB+ debt.

The AER has a limited discretion in making its decision on the rate of return

Under the Transitional Rules, the AER must determine the nominal risk free rate on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years using the indicative mid rates published by the RBA.

The moving average is based on a period of time which is either:

- proposed by the DNSP (averaging period) and agreed by the AER (agreed period); or
- in the absence of an agreed period, a period specified by the AER.

In considering the selection of the averaging period (whether that proposed by the service provider or that specified by the AER), the AER must have regard to the role of the averaging period in the context of the objects and purpose of the Rules and NEL, which relevantly include:

- the objective of the law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of users with respect to price, quality, safety, reliability and security of supply (section 7 of the NEL);
- a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in, relevantly, providing direct control network services (section 7A of the NEL);
- the network service provider is entitled to a return on capital calculated in accordance with clause 6.5.2 (clause 6.4.3(a)(2) of the Rules);
- the return on capital is to be calculated by applying a rate of return to the value of the regulatory asset base for the relevant distribution system (clause 6.5.2(a) of the Transitional Rules);
- the rate of return for a DNSP is the cost of capital measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the distribution business of the provider and must be calculated as a nominal post-tax WACC in accordance with the formula prescribed in the rules (clause 6.5.2(b) of the Transitional Rules); and
- the relevant WACC parameters have been fixed, other than the risk free rate and the debt risk premium.

[96] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p222

[97] CEG, *Rate of return and the averaging period under the National Electricity Law*, 14 January 2008, p4. (Attachment 8B)

8. Rate of return (continued)

In short, the averaging period for the risk free rate and the debt risk premium should be determined in a manner that is likely to provide a rate of return on capital consistent with providing the network service provider with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services and in the context of fixed parameters.

The Transitional Rules give "first choice" of the averaging period to the network service provider. Clause 6.5.2(c)(2)(i) provides that the AER is not to "unreasonably withhold" its agreement. In this context, the provisions require more than that the AER have some reason for not agreeing to the proposed period. If something more was not required from the AER, the specific rule formulation and sequencing that has been set out in clause 6.5.2(c) would serve no purpose as the AER's decision would simply revert to being subject to the general principles of administrative law (for example, "unreasonableness having regard to all the circumstances"). It follows that within the context of clause 6.5.2(c), to "unreasonably withhold" means something different.

To give operation to the structure of the Rules, and the service provider's right of "first choice" of the averaging period, the AER must consider whether the service provider's proposed averaging period is consistent with the role of the averaging period in determining the rate of return on capital.

The extent of the AER's discretion in considering the proposed averaging period is further constrained by clause 6.12.3 of the Transitional Rules, which relevantly provides that in the exercise of AER's discretion to accept or approve, or to refuse to accept or approve, any element of a regulatory proposal, if the AER refuses to approve an amount, value or methodology referred to in clause 6.12.1 (including the rate of return), the substitute amount, value or methodology on which the distribution determination is based must be:

(1) determined on the basis of the current regulatory proposal; and

(2) amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

Accordingly, if the proposed averaging period is consistent with the Rule and NEO, then the AER cannot withhold agreement simply because it prefers another period. To do so would be unreasonable and contrary to clause 6.12(3)(f) of the Transitional Rules.

Accordingly, the AER's first task is to consider the case advanced by the service provider for its proposed period and, only if it considers that the period is not consistent with the relevant Rule and NEL provisions, can it withhold agreement. If the AER concludes that the proposed averaging period is not consistent with the Rules, then it must set out its reasons.

Importantly, the AER cannot simply proceed to consider a period that it would agree to. Nor can it withhold agreement simply because the service provider has not proposed a period consistent with the AER's preferred regulatory practice. In each case, the AER would in effect give primacy to its preferred choice of period. This, in effect, renders worthless the right of the service provider to propose its own period.

Further, in considering whether to agree or not to the service provider's proposed period, the AER should give full consideration to that averaging period against the relevant Rule and NEL provisions. For example, the AER should not approve capital expenditure on the basis that the expenditure is prudent and efficient, and then select an averaging period that would provide a return on capital insufficient to meet the return required by investors in a commercial enterprise of similar risk to the distribution business.

The AER should have regard to whether the selection of the averaging period in determining the rate of return provides a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services.

Finally, it is not sufficient that the AER simply have a reason for withholding agreement (or specifying another period). Those reasons must be relevant reasons, they must be cogent and where they are based on theoretical or empirical assumptions or premises, the AER must consider whether there is a proper basis for those assumptions or premises. It is not open to the AER to merely specify a reason for withholding agreement, without testing whether the reason logically holds or has a proper basis.

8.2 The AER's decision to withhold agreement to EnergyAustralia's proposed averaging period

EnergyAustralia's June regulatory proposal

EnergyAustralia nominated a period of 15 business days commencing 2 June 2008 for the averaging period in a confidential attachment to the June regulatory proposal.[98] This was supported by a CEG report which discussed the averaging period proposed by EnergyAustralia.[99]

EnergyAustralia noted that its proposed period is reasonable within the context of its use in setting expectations of future returns over the 2009-14 regulatory period. Further we noted that in light of the significant capital program contained in our proposal, there is considerable business certainty afforded by establishing the rate of return early. This would enable EnergyAustralia to commence the initial phases of negotiating to secure the significant capital required to fund the capital expenditure program.

EnergyAustralia re-iterated its reasons in a letter to the AER on 2 July 2008. We noted that the timing of the proposed averaging period would provide the business with increased levels of certainty to allow Energy Australia the ability to confidently secure, or implement risk management strategies for raising the necessary funds to undertake the capital and operating programs over the forecast regulatory period.

The AER's decision to withhold the proposed averaging period

In its draft determination, the AER made a constituent decision under clause 6.12.1(5) of the Rules on the rate of return to apply to EnergyAustralia.

The AER's draft determination essentially reflects the reasons for rejecting EnergyAustralia's proposed averaging period and for specifying its own period under clause 6.5.2(c)(2) of the Transitional Rules. The AER's reasons are more fully set out in its letter of 8 July 2008 advising EnergyAustralia that it did not agree with EnergyAustralia's proposed averaging period.

In summary, the AER:

- did not agree with the averaging period proposed by EnergyAustralia, as the starting date was too far removed from the date by which the AER was likely to publish the final determination (expected to be in April 2009), and the commencement of the 2009-14 regulatory control period;
- considered the averaging period proposed by EnergyAustralia was contrary to accepted regulatory practice as reflected in previous AER and ACCC determinations, the ACCC's Statement of Regulatory Principles and previous jurisdictional regulators' determinations, all of which it said applied a nominal risk free averaging period considerably closer to the final determination date;
- noted that its regulatory practice is supported by accepted expert views in economic and finance literature and cited three expert reports;
- noted that CAPM theory suggests that, ideally, the nominal risk free rate will be calculated on the day of the final determination as the CAPM is an ex ante model and therefore the most up to date information should be used if available;
- stated that applying an averaging period which is closely aligned to the date of the final determination provides an unbiased rate of return that is consistent with market conditions at the time of the final determination.

In addition to the preference of the AER to adopt a period consistent with regulatory precedent, the essential premise of the AER's reasons set out above appears to be that CAPM theory suggests the most proximate date for the averaging period provides the best information for an unbiased estimate of the rate of return.

The AER noted what it referred to as EnergyAustralia's concern about the need for certainty in order to manage its commercial risks and the CEG opinion that 'a particular business may wish for greater early certainty about its allowed rate of return'. However, the AER did not agree that this premise went to the issue of applying an averaging period, the purpose of which it

[98] Attachment 8.1 to the June 2008 regulatory proposal
[99] Attachment 8.2 to the June 2008 regulatory proposal

said was to address the possible daily volatility in financial markets. The AER concluded that:

- the regulatory determination itself provides a distribution network service provider with certainty in relation to the rate of return that will apply during the forthcoming regulatory control period;
- further, this information is provided to the service provider prior to the commencement of the regulatory control period.

Accordingly, the AER concluded that early certainty of EnergyAustralia's allowed rate of return was not necessary for EnergyAustralia to deliver on its proposed capital expenditure program for the upcoming regulatory control period.

The AER's decision to withhold agreement was incorrect

EnergyAustralia considers that the AER's decision to withhold agreement was unreasonable and not permitted under the Rules. We consider that EnergyAustralia's proposed averaging period in June represented an appropriate proxy for the risk free rate in accordance with the Rule requirements and should have been agreed to by the AER.

It is noted that the AER referred to consistency with what it referred to as past regulatory practice but did not review such practice or the context for such practice in its reasons.

Further, the AER referred to economic literature to support its claim regarding consistency with the CAPM. However the AER did not review the context of that literature, nor did it discuss how that literature supported the AER's claim in its reasons.[100] Finally, the AER did not consider the circumstances in which the most proximate date for the averaging period may or may not provide the best information for an unbiased estimate of the rate of return. It appears that the AER simply assumed this to be the case.

We have set out at attachment 8A a detailed review of the AER's reasons for withholding agreement to EnergyAustralia's proposed averaging period. [101] As is clear from that detailed analysis, the AER's reasons:

- do not reflect the proper application of the Rules;
- are not supported by a proper consideration of past regulatory practice and the expert reports the AER relies on;
- rest on an untested assumption that the most proximate date for the averaging period will result in unbiased estimate of the rate of return. Subsequent events have established this assumption to be incorrect.

Recent events in financial markets should be reflected in any decision the AER makes in respect of the rate of return. This is discussed in the next section below.

8.3 The AER's substituted averaging period

Based on the reasons outlined in the above section, the AER did not agree to EnergyAustralia's proposed averaging period and instead proposed a new averaging period for EnergyAustralia of 15 business days starting on [redacted] and ending on [redacted] Where EnergyAustralia did not agree with this period, the AER requested that EnergyAustralia chose an alternative 15 day averaging period between [redacted] and [redacted]

In addition, while not stated in its reasons for its draft distribution determination or in its letter of 8 July 2008, it appears from an AER news release dated 29 November 2008 that the AER also prefers a later averaging period as it may lead to a decline in the debt risk premium and consequently a lower

100 Martin Lally, *The cost of capital for regulated entities, report prepared for the Queensland Competition Authority*, 26 February 2004, p63; Martin Lally, *Determining the risk free rate for regulated companies, report prepared for the ACCC*, August 2002, p17; and Davis, Kevin, *Report on risk free interest rate and equity and debt beta determination in the WACC*, report prepared for the ACCC, 28 August 2003, p16

101 EnergyAustralia, *AER's decision to withhold agreement*, January 2009 (Attachment 8A)

cost of capital, resulting in lower prices to consumers (Attachment 8C).[102]

The current global financial conditions and why it is necessary to incorporate its impact when making a decision

The AER's decision to withhold agreement and specify an alternative period closer to the regulatory control period was made within 30 business days of EnergyAustralia's proposal being lodged on 2 June 2008.

As noted above, the decision was based on an assumption that the most proximate date for the averaging period will result in an unbiased estimate of the rate of return.

The AER's decision was made prior to the significant impacts of a supervening critical event being demonstrated on global financial markets. This event is discussed in detail in section 8.4. While this event could not have been predicted with certainty, the probability of events of this nature occurring was clearly heightened at the time the AER took its decision. This event is highly likely to impact financial markets during the AER's specified period.

While EnergyAustralia considers the AER was wrong to reject its proposed averaging period, nonetheless to address the AER's reasons for its rejection, EnergyAustralia has revised its regulatory proposal bringing forward the commencement date.

EnergyAustralia acknowledges that it has not brought the forward commencement date to a date as close to the final decision as the AER had decided was appropriate.

It is critical that the AER considers the impact of the supervening critical event when making its decision on the averaging period and the rate of return that applies to EnergyAustralia.

In doing so, we provide the most up to date information on financial markets to ensure that the AER can make its decision on the most relevant and timely information. We also provide evidence demonstrating that observations of the nominal CGS yields using an averaging period in the current financial crisis will result in an unreliable estimate of the rate of return required under the Rules.

8.4 The supervening critical event

EnergyAustralia engaged CEG to provide information on the events currently affecting global financial markets and its implications for setting the rate of return for our business.[103] Their analysis is provided in Attachment 8B to this proposal. The material presented in that report clearly demonstrates that the events currently affecting global financial markets are unprecedented in their nature. This, combined with the continuing impact of the events represents a supervening critical event since the AER made its initial decision which has continued through to the AER's draft determination and almost certainly will still be in play when the AER makes its final determination.

A background to the supervening critical event is provided in Appendix B of the CEG report, which is summarised briefly here:

- This financial crisis had its origins in the US subprime mortgage market. Housing prices in the US fell with the effect that many subprime borrowers had negative capital in their homes (ie, house prices fell by more than the initial deposits). This gave these borrowers a financial incentive to cease meeting mortgage obligations which they did in large numbers.
- As a consequence, the value of these loans (held by financial institutions by way of complex derivative products) also fell. This led to a general unwillingness of banks to lend to each other with a worldwide "credit crunch" being reported in August 2007 and the central banks in the US, Europe, Japan, Canada and Australia coordinating in efforts to increase liquidity in financial markets.
- This credit crunch had a depressing effect on the real economy providing a 'feedback loop' in the form of

[102] AER, "Regulator's draft decision approves increased investment in NSW electricity distribution network" News release issued by the AER on 28 November 2008 entitled (Release # MR 017/08).

[103] CEG, *Rate of return and the averaging period under the National Electricity Law*, 14 January 2008, p4. (Attachment 8B)

increasing loan arrears and increasing uncertainty about the viability of key financial institutions.

- Arguably, the crises came to head in September 2008 – although the events of September 2008 were the subject of open market and media speculation in the immediately preceding months.

On Sunday 7 September 2008 the two largest buyers and securitisers of US mortgages ('Fannie Mae' and 'Freddie Mac') were placed in conservatorship. On Sunday 14 September 2008 the bankruptcy of investment bank Lehman Brothers and the sale of Merrill Lynch to Bank of America (with US government guarantees attached) were both announced. On Tuesday 16 September 2008 it was announced that the US Government would effectively take over 80% of the equity in one of the world's largest insurers (AIG) which had suffered a liquidity crises and was unable to find lenders to save it from insolvency. The US Government provided an $85 billion credit facility in exchange for taking over 80% of the equity in AIG.

While financial impacts have been evident since 2007, the significant impact on financial markets has become apparent in recent months.

CEG notes that both the OECD and the IMF indicated that September 2008 represented a break point in the development of the crisis[104]:

> The financial crisis that first erupted with the U.S. subprime mortgage collapse in August 2007 has deepened further in the past six months and entered a tumultuous new phase in September.[105]
>
> This Economic Outlook represents a substantial downward revision from just a few months ago: many of the downside risks previously identified have materialised. The financial turmoil that erupted in the United States around mid-2007 has broadened to include non-bank financial institutions and rapidly spread to the rest of the world. Following the collapse of Lehman Brothers in mid-September, a generalised loss of confidence between financial institutions triggered reactions akin to a 'blackout' in global financial markets.[106]

How the financial crisis has impacted required returns for debt and equity investors

CEG considers that the cost of equity rises during a financial crisis and supports this view with accepted finance literature (both empirical and theoretical).

CEG notes:

> Financial crises increase the uncertainty associated with the value of corporate assets and, as a consequence, increase the volatility of equity and corporate debt investments – both individually and as an asset class. Standard asset pricing theory predicts that investors dislike higher levels of volatility and demand a higher risk premium to provide capital in such circumstance. Indeed, Ghysels, Santa-Clara, and Valkanov (2005) describe this as "the first fundamental law of finance".[107]

CEG cites the supporting views of the RBA, as set out in its Statement on Monetary Policy in November 2008, which states:

> The falls in the share market over the past three months have resulted in a continued decline in the trailing P/E ratio, which is based on earnings for the past year. The forward P/E ratio, which is based on expected earnings for the coming year, has experienced a similar decline but would pick up somewhat if earnings expectations are revised down (Graph 59). Both the forward and trailing P/E ratios remain well below their long-run averages and around the lowest levels since 1991. P/E ratios for all three broad sectors of the share market are also below their long-run averages.[108]
>
> CEG notes that historically low levels for the P/E ratio (which would now be lower than at the time of the RBA statement) support

[104] CEG, *Rate of return and the averaging period under the National Electricity Law*, 14 January 2008, p4. (Attachment 8B)
[105] OECD Economic outlook number 84 is cited in CEG's report (p31 of Attachment B)
[106] IMF World Economic Outlook is cited in CEG's report (p31 of Attachment B)
[107] This is referenced in CEG's report to Ghysels, Santa-Clara, and Valkanov, Journal of Financial Economics Volume 76, Issue 3, June 2005, Pages 509-548 quoted in 2009 (p26 of Attachment B)
[108] CEG, *Rate of return and the averaging period under the National Electricity Law*, 14 January 2008, p4. (Attachment 8B) p34.

> CEG's view that the cost of equity at this period in time is at historically high levels.[109]

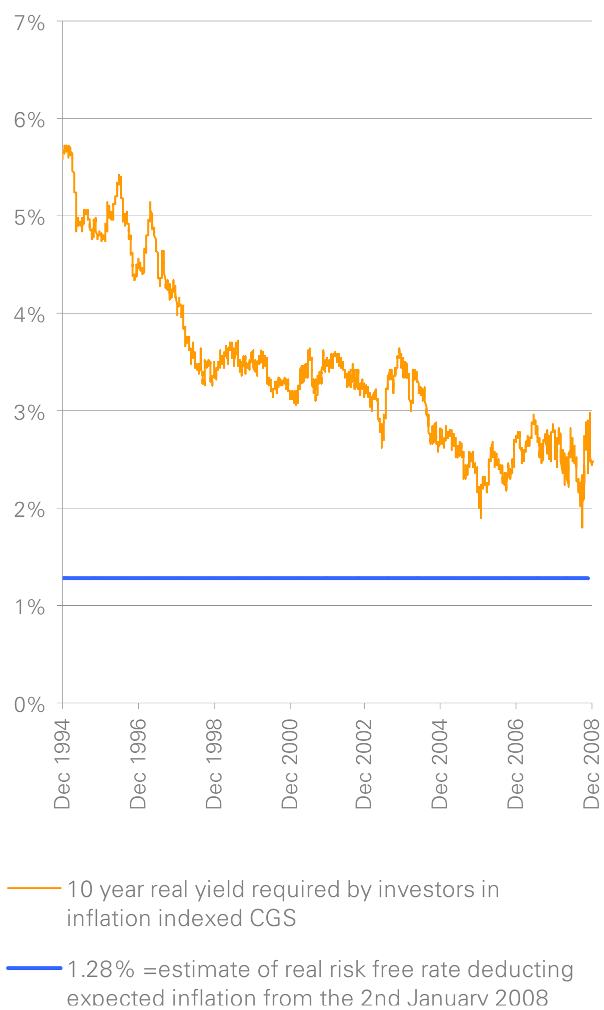
Deloitte, in its report to the AER as part of its review of WACC parameters noted the implications for expected returns for investors in corporate debt:

> The recent financial crisis demonstrates that in times of severe market conditions, liquidity in the primary and secondary markets can decline or even disappear. The lack of liquidity in the primary debt market implies business entities cannot raise finance via debt issuance without paying higher borrowing costs, since the demand for capital out-weigh the supply of capital in the market. On the other hand, the lack of liquidity in the secondary market implies capital providers in the primary market (investors) cannot convert debt securities to cash quickly at reasonable prices and hence would demand a higher rate of return from investments in the debt market. In both cases, the lack of liquidity will result in the addition of a liquidity premium to the investors required rate of return and hence will increase the costs of accessing debt.[110]

How the financial crisis has impacted market observations of nominal CGS yields

CEG notes that there has been an inverse movement in the observation of nominal CGS yields. On 2 January 2008, the nominal yield on 10 year CGS (3.94%) was the lowest value for the 10 year nominal CGS yield going back as far as the RBA publishes daily data (back to July 1992)[111]. This is highlighted in figure 8.1[112]

Figure 8.1 History of 10 year CGS nominal yields



This unprecedented low level for nominal CGS is evidence of the effect of the global financial crisis. As described below, relying on such a low estimate of the risk free rate when setting the cost of equity will not provide the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by EnergyAustralia as is required by the Rules.

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[109] The P/E ratio is a measure of how much companies have to pay (in the form of earnings) in order to attract equity investors. Or, equivalently, how much investors demand (in the form of earnings) for each dollar of equity they buy. A halving of the P/E ratio suggests (other things constant) that investors require double the compensation (in the form of earnings) for buying equity.

[110] Deloitte, *Refinancing, Debt Markets and Liquidity*, 12 November 2008, p18.

[111] CEG, *Rate of return and the averaging period under the National Electricity Law*, 14 January 2008, p34. (Attachment 8B) 2009 CEG report p30

[112] On 2 January 2009 the RBA reported yield on nominal CGS maturing in March 2019 was 3.96%

8. Rate of return (continued)

The abnormal nature of current nominal CGS yields can be seen by comparing these with indexed CGS yields. In normal economic times the difference between these yields is an indicator of expected inflation (this is known as the 'break even' inflation rate as it is the future inflation rate that will leave a long term investor in CGS with the same return irrespective of whether they invest in nominal or indexed CGS).

In its draft determination, the AER argued that this measure of expected inflation was artificially high. It stated:

> Historically, the AER has used an objective market-based approach to forecast the expected inflation rate—calculated as the difference between the CGS (nominal) and the indexed CGS yields. However, since late 2006 a downward bias in the indexed CGS has become evident due to the limited supply of these securities. Consequently, using this method potentially yields an overestimate of expected inflation.[113]

However, in a very short space of time recent events on financial markets have completely 'flipped' this position. Now the break even inflation rate is well below expected inflation (at least well below the AER's proposed measure of expected inflation).

This has been caused by the dramatic fall in nominal CGS yields that have not been matched by falls in indexed CGS yields. Consequently, the 10 year break even inflation rate fell from an average of 3.9% in May 2007 (which, consistent with the AER's reasoning above appears higher than actual expected inflation) to 1.8% on 2 December 2008 and 1.5% on the 2 January 2009. These later observations are well below both the AER's estimate of expected inflation and the RBA's target range for inflation. The current 10 year break even inflation rate is more than 1% below the AER's best estimate of expected 10 year inflation.[114]

CEG notes that it is not surprising to observe such abnormalities during periods of financial crisis. CEG states:

> It is a well documented fact that in times of market volatility there is what is known as a 'flight to liquidity' as well as a 'flight to safety'.[115]

CEG notes that nominal CGS are much more liquid than indexed CGS. As a consequence, CEG is not surprised that the more liquid CGS have their price bid up to abnormal levels (and yield pushed down to abnormal levels) during a financial crisis relative to yields on indexed CGS.

8.5 The AER's substituted averaging period and why it is demonstrably inappropriate

The period specified by the AER is neither supported by regulatory precedent or financial theory underlying the CAPM model in the current market environment and given the specific operation of the cost of capital rules in clause 6.5.2 of the Transitional Rules.

In these circumstances, the AER's specified period is not an appropriate period for determining the nominal risk free rate used for calculating the rate of return under clause 6.5.2. In particular, expert evidence demonstrates that using an averaging period during the height of a time of global financial crisis will result in an unreliable estimate of the rate of return required by investors under the Rules.

The AER's proposed averaging period is demonstrably inappropriate because:

- There is ample evidence that current nominal CGS yields are abnormally affected by the global financial crisis.
- An averaging period that captures this historically unprecedented low nominal CGS yields will give rise to an historically low cost of equity (both nominal and real) under

[113] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, pp226-227

[114] The AER's best estimate of inflation over 10 years is 2.63 per cent. This led CEG to state that the liquidity premium is depressing nominal bonds relative to indexed bonds by at least 0.86 per cent. On more recent data for 2 January 2009 this would be 1.13% (2.63% less break even inflation of 1.5%)

[115] CEG, *Rate of return and the averaging period under the National Electricity Law*, 14 January 2008, p32. (Attachment 8B)

the Rules when, in the midst of a financial crisis, the true cost of equity is at historically high levels.

- The AER needs to select an averaging period that eliminates the impact of abnormal events on the CGS market. This view is supported by;
  a. finance logic – especially in the context of the fixed parameters under the Rules;
  b. the academic reports the AER references in its 8 July 2008 letter to EnergyAustralia; and
  c. the regulatory precedent the AER references.
- In terms of estimating the DRP under the Rules using a current averaging period, there is strong evidence that illiquidity in corporate debt markets (induced by the financial crisis) makes this extremely difficult, if not impossible. Moreover, application of the AER's methodology for estimating the DRP under the Rules will give biased estimates in current market conditions.
- Finally, adoption of an averaging period where CGS yields are affected by the global financial crisis (in the manner they currently are) will result in serious internal consistencies within the AER's overall regulatory methodology.

Current observations from the CGS market are abnormal

As documented by CEG, there is ample evidence that nominal CGS yields are currently abnormally affected by the global financial crisis. In summary, these yields:

- are at historically unprecedented low levels;
- are at historically unprecedented low levels relative to indexed CGS yields;
- are at historically unprecedented low levels relative to other riskless assets (such as state Government debt);
- imply real returns (ie, after adjusting for expected inflation) that are at historically unprecedented low levels; and
- imply real returns that are significantly lower than guaranteed real returns from buying indexed CGS.

In terms of actual numbers:

- The yield on 10 year nominal CGS on 18 December 2008 was at 4.0% for the first time ever. This compares to an average of 5.8% over the preceding 10 years and 6.4% since 1994 (the longest data series available on the RBA website).
- On the same date, the difference between nominal and indexed CGS yields was 1.5%. This is lower than any value ever observed before December 2008 and compares with an historical average over the last ten years of 2.7% (2.8% since 1994);
- On 15 December 2008 the difference between 10 year nominal CGS and State Government debt[116] reached an historic peak of 1.2%;
- The associated real return on 10 year nominal CGS is also at an historically low level. On 18 December 2008 this was at 1.4%.[117] That is, an investor in nominal CGS would expect to earn a return of just 1.4% pa over 10 years.
- This compares with a guaranteed real return available on indexed CGS on the same date of 2.5%. That is, an investor could earn close to double the real return on nominal CGS simply by buying indexed CGS on the same date instead.

As CEG demonstrates, these abnormally low yields for nominal CGS (absolutely and relative to other default free assets) are a direct consequence of the global financial crises. This has important implications for the extent to which observations during this period will be reflected in any rate of return calculation.

Historically low cost of equity cannot be justified

Importantly, these abnormally low observations for the yield on nominal CGS are occurring at the same time that the cost of equity is at abnormally high levels.

CEG provides evidence which demonstrates that during times of financial crisis, the actual cost of equity will tend to be historically high. It is counter-intuitive for investors to demand a

[116] As estimated by CBASpectrum

[117] Calculated as the yield on nominal CGS on that date (4.02%) less the AER estimate of expected inflation (2.63%) divided by 1.0263 (as per the Fisher equation).

lower return in times of financial crisis than under normal conditions. Instead, investors require higher rates of return.

However, calculation of the return on equity under the Rules does not capture the high actual cost of equity as under the Rules the value of the Market Risk Premium (MRP) is "locked" in. This is despite the MRP being much higher than its prescribed value as a result of the global financial crisis.

At the same time, the calculation of the return on equity under the Rules allows for movements in the nominal risk free rate.

Given that the MRP is fixed at a level that reflects a long term average - not fixed at a level reflecting an abnormal market environment - it is appropriate to select an averaging period that is also not affected by abnormal market conditions.

CEG explains:

> If the NER (National Electricity Rules) allowed the risk premium associated with equity to be updated to reflect the actual prevailing risk premium then adopting an averaging period in the midst of a financial crisis need not result in an underestimate of the cost of equity. A lower risk free rate (reflecting the liquidity premium associated with nominal CGS) would be offset by a higher risk premium attached to equity. However, the NER does not allow this flexibility so the choice of averaging period becomes critical.[118]

The implication of this analysis is that observations of abnormally low yields on nominal CGS over a period of financial crisis should not be used to estimate the nominal risk free rate. To do so would result in a rate of return systematically lower than that required by investors over the next regulatory period.

Finance theory and regulatory precedent both support an earlier averaging period

The AER draft determination states that, ideally, the rate of return should be as current as possible.[119] Despite this, the AER notes that it does not use a single day observation for setting the risk free rate:

> While it may be theoretically correct to use the on-the-day rate as it represents the latest available information, this can expose the DNSP to day-to-day volatility. For this reason, an averaging method is used to minimise volatility in observed bond yields.[120]

The use of an averaging period under the NER is an acknowledgement that:

- market observations of nominal CGS bond yields are not a perfect proxy for the risk free rate;
- there is a risk that the risk free rate will be determined when trading might be characterised as 'unusual';
- it is desirable to reduce the impact of any such 'unusual' events on the average of the observations.

The Transitional Rules provide flexibility regarding the period of time (including the length of the period) for the measurement of the nominal risk free rate. This flexibility means that where abnormal events may be occurring in the market, the measurement of the nominal risk free rate may be adjusted to ensure that any forward looking rate of return remains appropriate.

The concept of smoothing or removing abnormal observations is relevant to the AER's decision on the averaging period. If the entire averaging period includes 'unusual' observations, then the AER must use the discretion afforded to it in Law and Rules[121] in determining whether the period can be relied on for setting a rate of return required by investors.

In summary, to be consistent with finance theory, the AER would need to set an averaging period that was most likely to lead to an appropriate estimation of the cost of equity and the cost of debt, taking into account all available information.

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118 CEG, *Rate of return and the averaging period under the National Electricity Law*, 14 January 2008, p38. (Attachment 8B).

119 We note our concerns with this approach in attachment 8A and why we don't believe the AER was reasonable in rejecting our proposed averaging period. In particular we note that in EnergyAustralia's particular circumstances a decision to establish a benchmark required rate of return well before the beginning of the period to determine an appropriate financial management strategy and enter into arrangements to secure equity and debt raising before the period.

120 AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p222

121 Section 8.1.1 outlines the AER's requirements in exercising discretion under 6.12.1(6).

Why the AER's references to finance literature do not support its averaging period

EnergyAustralia engaged CEG to assess the reports referred to by the AER in support of its proposed period in the context of the current financial conditions.

As CEG notes the papers referred to by the AER do not consider the appropriate approach to averaging in circumstances where the regulator is constrained by the Rules and is not able to update the MRP based on the most recent information. Nor were these papers specifically focussed on an appropriate approach in the context of a supervening critical event (which we are currently experiencing).

CEG's analysis of these papers suggests that the finance literature referred to by the AER does not support the period proposed by the AER. CEG explains:

> It would appear entirely consistent with this [Lally and Davis papers] advice that, if the yields on CGS were likely to be aberrant, due to the global financial crisis, over the entire averaging period then a different averaging period would be preferred that was less affected by the global financial crisis.[122]

The AER's own draft determination highlights the incorrect outcomes that can occur as a result of applying the calculation of cost of capital in a period of global uncertainty and volatility:

> The global financial crisis may impact on the price of electricity by raising the weighted average cost of capital used to determine the NSW DNSPs' allowed revenues. The cost of capital has fluctuated from around 9 per cent in early 2007, up to around 11 per cent in mid-2008. However, since then the cost of capital has fallen to 9.72 per cent, as at 17 October 2008.[123]

However, available evidence suggests that the actual cost of capital increased from mid 2008 to October 2008, EnergyAustralia is certainly not aware of any analysis that suggests that investors required rates of return that were lower in November 2008 than they were in mid 2008.

[122] CEG, *Rate of return and the averaging period under the National Electricity Law*, 14 January 2008, p11 (Attachment 8B).

[123] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, pXV

The AER's conclusion that the "cost of capital has fallen" since mid 2008 is not an empirical observation on the real cost of capital, but simply the formulaic application of the WACC formula by using the most recent averaging period without any regard to setting an appropriate averaging period for the risk free rate which is likely to be consistent with the use of the fixed MRP in estimating the cost of equity.

The anomalous result, in which the cost of capital decreases as volatility increases and the return on equity is increasing, is as powerful a reason as any to conclude the selection of an averaging period affected by the current financial crisis is wrong.

In conclusion, the available evidence suggests that the global financial crisis is producing an anomalous downward bias on nominal CGS yields such that, measured in this period, they no longer provide an appropriate proxy for the risk free rate when calculating the return on equity and when the market risk premium is fixed.

Why the AER's proposed averaging period is not supported by regulatory precedent

The AER and other regulators in the past have used the flexibility in establishing the averaging period to remove days (or periods) that produce anomalous results.

The ACCC in its 2002 Powerlink decision[124], while noting its preference for a rate closer to the beginning of the regulatory control period, intentionally chose an earlier period, prior to 11 September 2001. The reason given was that the events that took place on 11 September 2001 had an abnormal impact on CGS markets. The ACCC stated:

> The Commission recognises that the events of 11 September have impacted on the risk free rate, however it believes that it is still too early to fully quantify this impact. Given this uncertainty, the Commission will adopt a forty-day moving average ending on 11 September rather than a forty-day moving average ending on the date of this decision.[125]

[124] ACCC, *Powerlink Revenue Cap Decision*, November 2001.

[125] ACCC, *Powerlink Revenue Cap Decision*, November 2001, p13.

Similarly, the Essential Services Commission of Victoria removed observations of any period following August 2005 in establishing a rate of return for the period of 1 January 2006 to 31 December 2010 in its 2005 electricity distribution pricing review. This was to ensure any downward bias it believed were inherent in observations after August 2005 were not included in the forward looking rate of return. The ESC stated:

> Based on this in principle approach, the Commission's preferred response is to identify a measurement period that is not influenced by the downward bias, and to sample interest rates from that period. Data after August cannot be relied upon at this time as it is unclear for how long the downward bias may persist. On this basis, the Commission considers that it is appropriate to use the latest market evidence available prior to the biasing event.
> The Commission has therefore applied a measurement period for the calculation of the risk-free rate as the last 20 trading days of July 2005. This amended measurement period excludes any potential downward bias in the month of August, as identified by Westpac and CBA.[126]

CEG provides substantial other evidence (both domestic and international) of overseas precedent where regulatory bodies make specific allowance for abnormal financial conditions when setting the rate of return.[127] This includes:

- OFCOM (UK telecommunications regulator) has adopted a nominal risk free rate higher than current observations and more reflective of the long term average;
- OFGEM recently concluded that it could not rely on market data due to exceptional factors pushing down interest rates;
- US regulatory precedent demonstrates that US regulators consider any anomalous behaviour of interest rates when determining a fair cost of equity.

DRP more likely to be mis-estimated in current market conditions

In recent months there has developed a stark difference of opinion between market participants on what is the prevailing fair value yield on 10 year BBB+ corporate debt – which the Rules require the AER to base its estimate of the cost of debt on.

CEG explore this issue and find that an estimate based on Bloomberg data (as used by the AER) results in a cost of debt 1.55% higher than an estimate using the alternative data source CBASpectrum. This level of disagreement is historically unprecedented with the average value of disagreement between 1 January 2004 and 30 June 2008 being just -0.18% and with a deviation from this mean never exceeding 0.50%.

CEG note that the current value of disagreement involves a deviation from the pre July 2008 mean of 7 times the historical standard deviation. If the difference in opinion is normally distributed then, based on pre July 2008 differences of opinion, there would be a less than 1 in 500 million probability of observing the current differences in opinion. [128]

This clearly demonstrates the fact that global financial crisis has made observing BBB+ 10 year corporate debt yields more difficult (increasing the scope for disagreement). Consequently, any averaging period that falls within this period of increased scope for disagreement is less likely to accurately measure the cost of debt for BBB+ 10 year debt than an earlier averaging period.

In addition, CEG cites recent evidence that CBASpectrum estimates of fair value are more accurate and reliable than Bloomberg estimates of fair value. We explore this more in section 8.2 below.

Conclusion

The above analysis demonstrates that the AER's proposed period, will lead to an averaging period affected by the current abnormal financial market conditions will provide an estimate of the rate of return under the Rules which is materially biased below the rate of return required by investors in a similar commercial business.

[126] ESC, *Electricity Distribution Pricing Review* – Final Decision, 2005, p343

[127] CEG, *Rate of return and the averaging period under the National Electricity Law*, 14 January 2008, p16. (Attachment 8B).

[128] CEG, *Rate of return and the averaging period under the National Electricity Law*, 14 January 2008, p23. (Attachment 8B)

8.6 EnergyAustralia's revised averaging period

In revising our proposal, we note the AER's draft determination addressed the issue of EnergyAustralia's proposed period. The AER's draft determination essentially reflects the reasons set out in its letter of 8 July 2008 for not accepting EnergyAustralia's proposed averaging period, proposed in June.

EnergyAustralia has addressed the AER's reasons by proposing a revised period of 15 days commencing 18 August 2008. This revised averaging period is the date closest to the regulatory control period but which excludes market observations that are subject to abnormal financial market conditions as discussed above.

Consistent with the AER's reasons for rejecting EnergyAustralia's original averaging period, we have revised our proposal to take into account the most up to date information on financial markets and its impact on setting a rate of return required under the Transitional Rules and NEL. EnergyAustralia's reasons for revising its averaging period also addresses the AER's reasons set out in its draft determination for not accepting EnergyAustralia's original proposed period.

The reasons for selecting the revised averaging period include:

- to reflect the above analysis which suggests the dates proposed by the AER in its draft determination will lead to an averaging period affected by the current abnormal financial market conditions and will provide an estimate of the rate of return under the Transitional Rules which is materially biased below the rate of return required by investors in a similar commercial business.
- to select a period prior to important milestones in the global financial crisis – notably the announcement that two largest buyers and securitisers of US mortgages ('Fannie Mae' and 'Freddie Mac') were placed in conservatorship on 7 September 2008.[129]
- to select a period consistent with regulatory precedent which suggests the AER and other regulators in the past have used periods close to the beginning of the regulatory period but which do not include periods where there is volatility or downward bias on observations.

EnergyAustralia has revised the averaging period proposed in the June 2008 regulatory proposal. The revised averaging period is 15 business days commencing 18 August 2008.

8.7 Adjustments to the rate of return if averaging period not accepted

If the AER does not accept EnergyAustralia's revised proposed period, EnergyAustralia considers the AER must make an adjustment to the rate of return that is calculated using the AER's specified period in order to ensure the rate of return applied to EnergyAustralia is consistent with the Rules and NEL. In light of the high likelihood that the AER's specified period will be subject to abnormal financial market conditions as a result of the global financial crisis, the AER should make adjustments to ensure that the 10 year estimate of inflation and the 10 year nominal risk free rate are applied consistently in the PTRM.

As described in the above sections, CEG demonstrate that under current financial market conditions, there is a disconnect between inflation expectations and break even inflation rates derived from CGS markets.

On 2 January 2009 the break even inflation rate was 1.5%. That is, investors were demanding only a 1.5% higher yield from nominal CGS (the yield of which is not inflation protected) than from indexed CGS (the yield of which is inflation protected). This is highlighted in figure 8.2.

There are only two internally consistent interpretations of this fact:

[129] Which was followed by the announced bankruptcy of Lehman Brothers investment bank and government backed buyout of Merrill Lynch investment bank one week later on 14 September 2008. Which was then followed by the announced failure and Government buy out of one of the world's largest insurers (AIG) on 16 September 2008.

8. Rate of return (continued)

- the nominal CGS yield is abnormally low relative to the indexed CGS rate – such that the former does not provide adequate additional compensation for inflation relative to the latter; or
- the nominal CGS yield is not abnormally low relative to the indexed CGS rate and inflation expectations are 1.5% over the next 10 years.

Figure 8.2 Inflation implied by the difference between the real and nominal 10 year CGS yields

In the first case the nominal CGS yield does not provide adequate compensation for inflation relative to the indexed CGS yield. Thus, a more accurate estimate of the nominal risk free rate is the yield on indexed CGS plus expected inflation.[130]

In the second case, the nominal CGS yield does provide adequate compensation for inflation relative to the indexed CGS yield. However, in this case one must adopt the break even inflation rate from the CGS market as the best estimate of expected inflation.

Thus, to ensure that inflation and the nominal risk free rate are applied consistently in the PTRM, the AER should either:

- use the 10 year indexed CGS bonds as a proxy for market observations of the real risk free rate and add the 10 year RBA estimate of inflation to determine a nominal risk free rate; or
- adopt the CGS break even inflation rate as its best estimate of expected inflation.

Either approach is permitted under the Rules and is more likely to result in a rate of return consistent with rule requirements than the alternative currently proposed by the AER.

These options are explained in more detail in section 4 of CEG's report.

8.8 Debt Risk Premium

The AER's draft determination included a decision on debt risk premium that was consistent with prior regulatory decisions and consistent with EnergyAustralia's June 2008 proposal. This decision included:

- that the observation for the debt risk premium should be determined with reference to the same averaging period that was adopted for determining the risk free rate;
- that the observation of corporate bond data be sourced by Bloomberg estimated average daily fair yields for corporate

[130] Although this will likely underestimate the true nominal risk free rate given the fact that, as noted by the AER in the draft determination, indexed CGS yields are artificially depressed by a lack of supply. Noting also that the yield on indexed CGS has not changed materially in the last six months.

bonds with BBB+ credit rating and maturity of up to 10 years.

The AER's cites analysis undertaken in respect of previous regulatory determinations as a basis for using Bloomberg data to calculate average daily fair yields for corporate bonds with BBB+ credit rating.[131]

The review indicated that Bloomberg's estimates of BBB+ rated long-term fair yields were more consistent with the observed yields of similarly rated actual bonds. The AER considered that its methodology based on data provided by Bloomberg remains appropriate for determining the debt risk premium.

EnergyAustralia comments

EnergyAustralia engaged CEG to review the effect of the supervening critical event on corporate bond yields. CEG found that the event has had a substantial impact on corporate debt markets. CEG notes that new corporate debt issues have effectively dried up and a significant reduction in the liquidity of existing bonds:

> … the lack of liquidity means that it is very difficult to meaningfully observe the cost of debt from trades in existing BBB+ bonds as required by the NER. However with limited and infrequent trading in these bonds it is difficult to accurately determine the true yield on BBB+ rated corporate bonds….
> The fair value yield on a specific credit rating and maturity is an estimate of the average yield that would prevail on a bond issued with that maturity by a representative firm with that credit rating. However, with fewer trades on existing bonds and no new bonds being issued the data necessary to determine the fair value yield becomes less available.[132]

This is evidence demonstrating that the supervening critical event may also be affecting the underlying data used to estimate corporate debt yields.

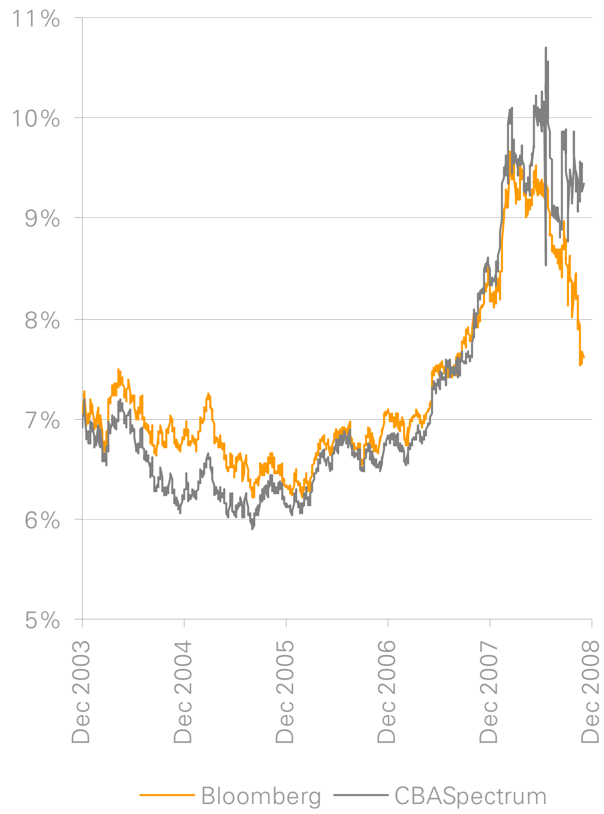
[131] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p225

[132] CEG, *Rate of return and the averaging period under the National Electricity Law*, 14 January 2008, p51. (Attachment 8B)

Concerns over Bloomberg data observations in an illiquid market

CEG has analysed the fair value yields estimated using both CBA spectrum data and Bloomberg data sources. Historically, while CBA spectrum's estimation technique is likely to bias down the estimate of BBB+ corporate bond yields, observations between the two data sources rarely deviated more than 0.5%, with CBASpectrum's estimate being the lowest.

Figure 8.3 10 year bond yield observations



CEG's analysis of observations over recent months reveals a significant deviation away from this historic trend. CBASpectrum observations are now estimating yields on

BBB+ bonds that are 1.55% higher than what Bloomberg is estimating for riskier BBB bonds.

Evidence suggests that under current market conditions neither Bloomberg or CBASpectrum data is likely to provide a reliable estimate of corporate bond yields. However it is equally true that the AER's previous conclusions regarding the consistency of Bloomberg data over CBASpectrum data need to be reviewed in light of new information.

Firstly, CEG notes that CBASpectrum has altered its methodology since the AER undertook its review of corporate bond yields. Secondly we do note that ESCV recently found that CBA spectrum performed better in predicting bond yields under current market conditions.

CEG outlines several options to overcome the difficulty caused by observing bond yields.

We do note that the AER used CBASpectrum to measure corporate bond yields for ActewAGL in determining the cost of capital and may be persuaded by consistent treatment across NSW and ACT businesses.

However, EnergyAustralia is persuaded by using some averaging approach to smooth the data observations. CEG notes[133]:

> An alternative approach to relying solely on one or the other of these data services would be to take a simple average of the two. This would be consistent with the AER's approach to estimating future prices for raw materials (copper, aluminium, crude oil etc) for the purpose of estimating future capex costs. In this case, the AER estimates these prices by taking a simple average forecasts provided by a number of market participants (and aggregated by Consensus Economics). A similar approach to estimating fair value for 10 year BBB+ yields would ensure that some weight was given to all bonds for which there is data in each data service. It would also give equal weight to the expert opinions embodied in the estimates of fair value from each data service.

EnergyAustralia's revised debt risk premium

EnergyAustralia revises its proposed debt risk premium in the original regulatory proposal using averaging period is 15 business days commencing 18 August 2008 and using an average of Bloomberg and CBA spectrum data observations. The revised debt risk premium is 3.22% representing the difference between nominal risk free rate observations (5.82%) and corporate bond yield observations (9.04%).

8.9 EnergyAustralia's rate of return

EnergyAustralia has revised its proposal to include updated values for the nominal risk free rate and debt risk premium

These values are set out in Table 8.1 and results in a proposed rate of return of 10.15 per cent

Table 8.1 WACC parameters and values in the PTRM

Parameter	Value
Nominal risk free rate	5.82%
Real risk free rate	3.19%
Inflation rate	2.55%
Cost of debt margin over risk free	3.22%
Nominal pre-tax cost of debt	9.04%
Market risk premium	6.0%
Proportion of equity funding	40%
Proportion of debt funding	60%
Equity Beta	1.0

[133] CEG, *Rate of return and the averaging period under the National Electricity Law*, 14 January 2008 (Attachment 8B)

9-11. Operating expenditure

REVISED PROPOSAL

EnergyAustralia has revised its June 2008 building block proposal ('June 2008 proposal') for the total of forecast required operating expenditure. The revised forecast operating expenditure is $2941 million ($09 Real), or $2991 million ($09 Real) including debt raising costs. The revision is to incorporate the substance of changes required to address matters raised by the draft distribution determination or the AER's reasons for it. This includes the matters raised by the AER regarding:

- Adjustment for the 'Year Zero' starting point and correction of error in the maintenance model, which results in a $24 million reduction from the June 2008 proposal.
- Updated forecasts of labour costs, which results in a $3 million reduction from the June 2008 proposal.
- Transferring equity raising costs from operating to capital expenditure, which results in a $49 million reduction from the June 2008 proposal.
- Consequential revisions to forecast operating expenditure to reflect other revisions in this proposal. This results in $4 million reduction from the June 2008 proposal.

This chapter together with chapters 9-11 of EnergyAustralia's June 2008 proposal (including all attachments and supporting information submitted in support of those chapters) now comprise EnergyAustralia's current proposal in relation to forecast operating expenditure. There are a number of additional attachments referred to in this chapter which should now be read in conjunction with June 2008 proposal including Attachment 9G which should be read in conjunction with Attachment 10.1. Figures and tables in the June 2008 proposal which refer to future costs and cost escalators are no longer current. Those figures and tables that refer to forecast operational expenditure for 2009-2014 regulatory control period may no longer be totally accurate but are still appropriate for illustrative purposes. Table 10.6 has been replaced by Table 9.1 in this Chapter.

Rule requirements

The AER's distribution determination is predicated on a decision in which the AER either:

(i) acting in accordance with clause 6.5.6(c) accepts the total of forecast operating expenditure for the regulatory control period that is included in the current building block proposal; or

(ii) acting in accordance with clause 6.5.6(d) does not accept the total of forecast operating expenditure for the regulatory control period that is included in the current building block proposal, in which case the AER must set out its reasons for that decision and an estimate of the total of the DNSP's required operating expenditure for the regulatory control period that the AER is satisfied reasonably reflects the operating expenditure criteria taking into account the operating expenditure factors. (Clause 6.12.1(4))

Our June 2008 building block proposal

EnergyAustralia proposed a total forecast operating expenditure requirement for the regulatory control period of $2.97 billion, or $3.07 billion including debt and equity raising costs (FY09 real). This was discussed in Chapters 9 to 11 of EnergyAustralia's June 2008 proposal.

AER's draft determination

The AER did not accept EnergyAustralia's total forecast operating expenditure for the next regulatory control period. The AER's estimate of EnergyAustralia's forecast required operating expenditure for the next regulatory period is $2.64 billion. The AER:

- reduced the total operating expenditure to remove certain 'step changes' by $303 million. This includes reductions in expenditure for network maintenance ($18 million); network operating ($213 million); and other operating business support ($70 million);
- reduced network maintenance expenditure by $36 million for maintenance escalation costs and adjustments to starting point data for the maintenance model;

9-11. Operating expenditure
(continued)

- reduced other operating expenditure by $13 million for asset/ project management escalation costs;
- reduced operating expenditure by $0.4 million to adjust for labour escalators;
- reduced self insurance costs by $9 million;
- reduced debt raising costs by $24 million; and
- reduced equity raising costs by $13 million and indicated its preference that equity raising costs be capitalised and therefore not included in the forecast operating expenditure.

Our response to the AER's draft determination

EnergyAustralia does not accept the AER's decision.

This chapter sets out in detail the reasons why EnergyAustralia does not accept the AER's decision, provides additional material in support of the material contained in Chapters 9- 11 of its June 2008 proposal and explains the revisions which have been made to its forecast operating expenditure. Specifically:

- Section 9.1 sets out the material provided in support of EnergyAustralia's forecast operating expenditure in its June 2008 proposal and notes our concern that the AER did not consider, or properly or fully consider, the material submitted by EnergyAustralia.
- Section 9.2 sets out the reasons why EnergyAustralia does not accept the AER's findings on step changes.
- Section 9.3 sets out the reasons why we do not accept the AER's findings on network maintenance expenditure. This section also details revisions to our proposal to address the "year zero" data for the maintenance model.
- Section 9.4 sets out the reasons why we do not accept the AER's findings on the workload escalator for the Asset and Investment Management and Major Project divisions.
- Section 9.5 notes that we do not accept the AER's findings on labour escalation. This section also revises our proposal to provide updated market data on labour forecasts.
- Section 9.6 sets out the reasons why we do not accept the AER's findings on self insurance.
- Section 9.7 sets out the reasons why we do not accept the AER's findings on debt raising costs.
- Section 9.8 notes that we do not accept the AER's findings on equity raising costs. EnergyAustralia however accepts the AER's finding to treat equity raising costs as capital expenditure and has revised its forecast of operating expenditure. For this reason, our submission on the AER's findings on equity raising costs is set out in the Chapter 3 of this revised proposal.
- Section 9.9 sets out the consequential revisions to the forecast of operating expenditure from other revisions to the proposal.
- Section 9.10 is a summary of EnergyAustralia's revised forecast operating expenditure.

9.1 Material provided by EnergyAustralia in support of its June 2008 proposal

EnergyAustralia submitted its operating cost forecasts in accordance the requirements of clause 6.5.6 of the Rules. EnergyAustralia's operating expenditure forecast methodology and the calculation of the forecasts are fully specified in the June 2008 proposal.

Chapters 9 to 11 of the June 2008 proposal set out EnergyAustralia's forecast methodology, forecast expenditure program, and how the forecasts align to the reflecting operating expenditure criteria. We also provided supporting information attached to the proposal detailing the operational expenditure forecasting used by EnergyAustralia.

The material submitted by EnergyAustralia complied with schedule 6.1.2 and 6.1.3(1) of the Rules, addressing each of the required matters relating to operating expenditure. This was demonstrated in supporting information attached to the proposal, in particular the document titled, "EnergyAustralia (Rules) Compliance Checklist Final".[134]

[134] EnergyAustralia, *DVD 2 of EnergyAustralia's regulatory proposal, Compliance checklist*, 2 June 2008.

In addition, EnergyAustralia provided the information in relation to its operating expenditure forecasts requested by the AER in the Regulatory Information Notice of 24 April 2008. This is demonstrated in the supporting document attached to the proposal, titled, "EnergyAustralia (RIN) Compliance Checklist Final".[135]

The AER was required to consider the submitted forecasts and the evidence and supporting material submitted by EnergyAustralia in substantiation of these forecasts. Under clause 6.12.1(4), the AER must accept forecast operating expenditure if it is reasonably satisfied it reflects the operating expenditure criteria taking into account the operating expenditure factors.

If the AER is not satisfied, then the AER must set out:

- its reasons for that decision; and
- an estimate of the total for the DNSP's required operating expenditure for the regulatory control period that the AER is reasonably satisfied reflects the operating expenditure criteria taking into account the operating expenditure factors.

If the AER refuses to approve an operating expenditure forecast the substitute amount, value or methodology on which the distribution determination is based must be:

- determined on the basis of the current regulatory proposal; and
- amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

This requires that the AER identify the particular elements of the operating expenditure forecast it does not consider meet the relevant rule requirements, set out its reasons why it does not consider that the forecast meets the requirements and then amend the forecast only to the extent necessary to enable approval.

As set out in the following sections, EnergyAustralia is concerned that the AER did not consider, or properly or fully consider, the material submitted by EnergyAustralia in support of its forecast of required operating expenditure.

9.2 Step changes

EnergyAustralia forecast its operating expenditure for the 2009-14 period using the audited operating costs from 2006-07 as the base year. EnergyAustralia applied three types of adjustments to the efficient base year costs to derive an efficient forecast of operating expenditure for the period:

1. Adjustments to take account of the real price of labour over the period ('real cost escalators');
2. Adjustments to take account of changes in the volume of work during the period ('workload escalators'); and
3. Adjustments (both increases and decreases) in costs for known changes to the drivers of cost activities ('step changes').

All three types of adjustments are important components of EnergyAustralia's forecast method and are required to derive a forecast that accurately reflects the efficient costs faced by a DNSP in the circumstances of EnergyAustralia.

While each of these adjustment mechanisms is important, the adjustment for step changes is the adjustment that received most focus by the AER and its consultants.

Step changes as used by EnergyAustralia, denote a 'step up' or 'step down' in the ongoing costs of an activity from a known change in the driver of these costs. If this expenditure was not included in the forecast, EnergyAustralia would be unable to recover the efficient costs incurred in providing standard control services, as required by the revenue and pricing principles in the NEL.[136] This is clear from the following examples of step changes:

- Land tax - The 'step up' in costs ($20 million adjustment) is driven directly by the increase in land tax payable due to the net change in EnergyAustralia's land holdings each year. EnergyAustralia would not be able to meet its obligations to pay land tax on accepted prudent and efficient investment in

[135] EnergyAustralia, *DVD 2 of EnergyAustralia's regulatory proposal, Compliance checklists*, 2 June 2008.

[136] National Electricity Law, Section 7A(2)

new substation and depot sites if this expenditure is not included in the forecast.

- Incremental IT - The ‘step up’ in costs ($44.1 million adjustment) is driven by incremental costs in IT - for instance the operating costs associated with implementation of iAMS (integrated Asset Management System). The benefits of the accepted prudent and efficient capital investment in these systems could not be realised without the accompanying operating expenditure required to operate and maintain these systems.
- Storms - The ‘step down’ in costs ($45 million ‘one-off’ negative adjustment) was made to account for higher than usual storm costs in 2006-07 due the June 2007 storm. If this step change is rejected, costs of unusual storm activity would remain in the base year and apply to all future years.

Step changes are therefore an important mechanism used by EnergyAustralia to either adjust costs in the starting base year to reflect normal cost levels, or to adjust costs in future years to reflect a specific driver (i.e. for example, implementation of a new system).

Wilson Cook was engaged by the AER to assess EnergyAustralia’s operating expenditure proposal. It recommended removing almost all step change expenditure items included in EnergyAustralia’s forecast, based on Wilson Cook’s own formulated criteria for assessing of those expenditure items.

The AER accepted Wilson Cook’s recommendation that the majority of EnergyAustralia’s proposed step changes did not meet the criteria for step change as proposed by Wilson Cook. The AER reduced EnergyAustralia’s operating expenditure by $303 million based on this finding. The AER considered that Wilson Cook’s analysis represented a robust assessment, noting that:[137]

- The step change criteria adopted by Wilson Cook to assess EnergyAustralia’s proposed step changes accord with the operating expenditure criteria (in the Rules) in that they ensure that any step changes reflect the efficient costs a prudent operator would require to achieve the operating expenditure objectives.
- Wilson Cook’s bottom up assessment was supported by Wilson Cook’s top down approach based on a benchmarking analysis. The AER noted that Wilson Cook found that EnergyAustralia’s base year operating expenditure increases at a much higher rate than the other NSW and ACT DNSPs and that over the next regulatory period, EnergyAustralia’s cost efficiency relative to other ACT and NSW DNSPs will deteriorate.
- Wilson Cook’s finding that the step change expenditure items do not include any consideration of business efficiency improvements, and, therefore has the potential to over-estimate the level of future costs.

The AER’s decision was to reduce expenditure by $18 million for network maintenance expenditure, $213 million for network operating expenditure and $70 million for other operating (business support) expenditure to remove step changes. The AER accepted Wilson Cook’s recommendation to include step change expenditure for apprentices, regulatory reset costs and self insurance costs.[138] Wilson Cook also accepted the negative step change to base year costs from a one-off storm event in 2006-07.

EnergyAustralia’s comments

We do not accept the AER’s finding to exclude $303 million of EnergyAustralia’s proposed expenditure relating to step changes.

In coming to its conclusions, the AER did not give sufficient or proper, consideration to the material in EnergyAustralia’s June 2008 proposal which demonstrates the prudence and efficiency of the step change expenditure. Instead the AER outsourced the assessment of expenditure driven by step changes to Wilson Cook and accepted its findings without further analysis.

[137] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, pp174-75

[138] Wilson Cook did not review self insurance. The AER reduced the proposed expenditure for self insurance by $9 million.

In this submission, we provide compelling evidence to demonstrate that Wilson Cook's advice was based on poor analysis, did not reflect the operating expenditure criteria in the Rules, and that its opinion was not informed by a proper review of EnergyAustralia's forecast. Specifically, Wilson Cook applied criteria for accepting costs driven by step changes that were too narrow. This resulted in prudent expenditure being rejected because it was characterised as being driven by a step change, rather than being assessed on the merit of each forecast cost. In light of this evidence, the AER must reconsider its findings with regard to step changes by carefully considering the material provided in our June 2008 proposal.

In this section we draw on the advice of Huegin Consulting who are experienced engineering and strategic management consultants. Huegin's advice raises many concerns with Wilson Cook's approach, methodology and analysis. Huegin also undertook a robust assessment of the expenditure driven by step changes to test whether the expenditure accords with the requirements in the Rules. Huegin's findings show that Wilson Cook's analysis was performed at a high level and was not sufficiently detailed or robust to enable a correct assessment or appropriate recommendations that the AER could rely upon. Huegin's advice is set out in Attachment 9A of this revised proposal.[139]

Our detailed submission on this matter is structured as follows:

- Section 9.2.1 identifies the material in EnergyAustralia's regulatory proposal relating to step change expenditure. We note that the AER has not assessed this material as required under clause 6.5.6(c) of the Rules.
- Section 9.2.2 provides evidence to demonstrate that Wilson Cook's analysis is poorly prepared and cannot be relied on by the AER.
- Section 9.2.3 sets out additional evidence from Huegin Consulting to demonstrate that individual step change expenditure is prudent and efficient.
- Section 9.2.4 sets out additional material to demonstrate that EnergyAustralia's total operating expenditure forecast accords with the operating expenditure criteria in the Rules.
- Section 9.2.5 is a summary of EnergyAustralia's submission on step changes.

9.2.1 Material provided by EnergyAustralia

EnergyAustralia submitted a regulatory proposal that complied with the information requirements in Schedule 6.1.2 of the Rules. We provided detailed information on our approach to developing the operating expenditure forecast in chapters 9 and 10 of the June 2008 proposal. This information was supported by detailed analysis and documentation to support our claim.

Chapter 11 of our June 2008 proposal specifically demonstrated how EnergyAustralia's proposed total forecast operating expenditure satisfied the requirement of clause 6.5.6 of the Rules. In particular we noted that:

- The forecast operating expenditure took into account expert advice from NERA about how a DNSP's forecast should be compiled to address the operating expenditure criteria in the Rules.
- The forecast took account of the specific circumstances of our business, in particular the large investment in network infrastructure that will require additional investment in operating support expenditure.
- We considered the operating expenditure factors in compiling the forecast and demonstrated how our forecasts satisfied the operating expenditure criteria.

In respect of expenditure driven by step changes, we provided substantial material in our June 2008 proposal to demonstrate that such expenditure reasonably reflects the operating expenditure criteria. This included:

- Section 10.2.1 which provided an explanation of the process used to escalate costs from the base year.
- Section 10.2.2 which specifically explained what step changes are and why they are important drivers of the forecast operating expenditure requirement.

[139] Huegin Consulting Group, *EnergyAustralia's regulatory proposal review (opex)*, January 2009.

- The operating expenditure model ('opex model') which was not submitted as part of the June 2008 proposal but which was provided to Wilson Cook and the AER on 22 August 2008. The model identifies the cost and timing of each step change in the forecast of required operating expenditure for each cost activity.
- Supporting information attached to the June 2008 proposal detailing the operational expenditure forecast process used by EnergyAustralia. This included the "Operating expenditure forecasting" document which set out the rationale, responsibility and source for each step change applied in the 'opex model'.
- Supporting information attached to the June 2008 proposal relating to step change expenditure on system and non-system IT. This included the "Network operational plan" (Attachment 4.11) and "Non-system IT capex" (supporting document). These documents detail the forecast incremental operating expenditure driven by system IT and non-system IT investment.
- Supporting information attached to the June 2008 proposal relating to the step changes from capital expenditure in property. This included the "Network property plan" (supporting document) and the "Corporate property strategy" (Attachment 4.12). The forecast of land values from the property plans was used to determine the forecast operating costs associated with property assets.
- Attachment 5.13 to the June 2008 proposal ("DM Impact on 2009-14 Capital Forecast") relating to step change expenditure on demand management.

The AER did not assess EnergyAustralia's material

The AER's draft determination did not refer to the substantial material provided as part of EnergyAustralia's June 2008 proposal. It appears the AER relied exclusively on Wilson Cook's opinion, which itself was not informed by a proper assessment of the material provided by EnergyAustralia.

It is clear from the Rules, particularly clause 6.5.6(c) of the Transitional Rules, that the AER is itself required to consider the detail of EnergyAustralia's proposal. It is not sufficient for the AER to delegate this task to a consultant and then simply rely on the conclusions of the consultant.

Nor can, or should, the AER simply rely on external consultant opinion as to the estimate of a building block proposal element, such as forecast operating expenditure, in rejecting a DNSP proposal. The AER itself is required to consider the DNSP's proposal informed by its consultants if necessary. In doing so, it is important that the AER properly assess and test its own consultant's material and weigh that material against the material submitted by the DNSP. That is, the AER cannot simply accept its consultant's opinion without properly testing it or satisfying itself that their experts tested it.

9.2.2 AER should not rely on Wilson Cook's advice

EnergyAustralia considers that the AER cannot rationally rely on Wilson Cook's advice. In this section we demonstrate that:

- Wilson Cook's top down benchmarking analysis cannot be relied on by the AER due to significant methodological errors in the application of the cost scale variable (CSV) analysis.
- Wilson Cook's own criteria of step change do not accord with the decision making process under the Rules and is not consistent with the operating expenditure criteria in the Rules.
- Wilson Cook's bottom up analysis did not reflect a proper detailed review of those cost items. Wilson Cook made simplifying assumptions in its step change criteria (namely that controllable step changes would be off-set by efficiencies) to avoid a detailed consideration of the actual items. Wilson Cook's approach lacked rigour and therefore cannot be relied on to inform judgement on the prudence and efficiency of expenditure driven by step changes.

In reviewing Wilson Cook's analysis, EnergyAustralia drew on the advice of Huegin. Huegin's' findings are set out in section 2.6 of its report at Attachment 9A.

Benchmarking analysis contained methodological errors

A key reason given by the AER for accepting Wilson Cook's recommendation on step changes was that Wilson Cook's top down benchmark analysis supported Wilson Cook's bottom-up assessment of step changes. We are concerned that the AER gave weight to Wilson Cook's top down analysis in accepting their advice on step changes.

Wilson Cook stated that it used an 'opex per size' measure (cost scale variable) to review the reasonableness of the forecast levels of total opex of NSW and ACT distribution businesses from a top down perspective.[140]

Based on the CSV analysis, Wilson Cook assessed the change in operating expenditure from 2007-08 to 2013-14 for ACT and NSW DNSPs. It noted that EnergyAustralia's operating expenditure increases at a faster rate than other DNSPs. Wilson Cook concluded that unless reasons can be established why EnergyAustralia should move further away from the industry norm, the level of opex in the next period could not be considered to be at an efficient level.[141]

EnergyAustralia considers that benchmarking has inherent limitations. Our view on comparing the costs of one DNSP against another was set out in section 11.5.1 of our June 2008 proposal. We agreed with NERA's advice that little can be said about the relative efficiency of the business once all of the characteristics of each DNSP's business and operating environments are considered.[142] Further, benchmarking assumes that the costs of other comparator businesses are forecast accurately.

The limitations of benchmarking are also acknowledged by Wilson Cook[143]:

> Benchmarking has limitations and thus, whilst broad comparisons of DNSPs may be made, various factors complicate the comparisons and require the exercise of considerable judgement when interpreting the results.

The outcomes of benchmarking should be viewed with caution and should not be considered as conclusive evidence of efficiency, but should be used to indicate areas for further investigation, and therefore be followed up with rigorous and detailed assessments of the detailed build up of expenditure forecasts. It is clear that Wilson Cook's did not test the outcomes of its benchmarking analysis by undertaking a detailed review of EnergyAustralia's proposed expenditure. Instead Wilson Cook appears to have relied exclusively on its application of the CSV benchmark analysis to justify removing step changes without an assessment of the repercussions of doing so, or whether this blanket rejection was consistent with its decisions in other parts of its own assessment report.

In addition to the inherent limitations of benchmarking, we note that Wilson Cook's CSV analysis contains errors relating to data, reasoning and methodology, and has been poorly applied in the context of this review. It is not apparent that Wilson Cook has any expertise or past experience in the application of CSV analysis. This is important as the CSV analysis is not simply a procedural application of a well accepted benchmarking analysis. CSV analysis is not a well accepted methodology for benchmarking and in any event requires the exercise of judgment and expertise in its application.

EnergyAustralia engaged Huegin Consulting to assess whether the CSV analysis could be relied on to inform judgements on the relative efficiency of EnergyAustralia relative to other DNSPs.[144] Huegin notes that the use of a CSV as a determinant of operating expenditure, particularly for Australian DNSPs has severe limitations and is open to challenge. This is because there are a small number of entities in the sample, and the variance in physical network characteristics is broad.

A key point raised by Huegin is that Wilson Cook's application of the CSV framework did not include any adjustments to account for differences between the businesses. Huegin notes that previous international applications of the CSV analysis took into account regional differences and factors outside the

[140] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 1, p17-30.

[141] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 2, p53.

[142] NERA, *Economic consulting economic interpretation of clause 6.5.6 and 6.5.7 of the NER*, p29. This was Attachment 6.1 of the June 2008 proposal.

[143] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 1, p17.

[144] Huegin Consulting Group, *EnergyAustralia's regulatory proposal review (opex)*, January 2009, Section 2.6 (Attachment 9A)

9-11. Operating expenditure
(continued)

control of management. In contrast, Wilson Cook provided negligible treatment of these factors. Huegin stated that Wilson Cook's analysis:

> … ignores any contribution to cost of other important factors such as network type, network age, business structures, etc. Failing to account for these cost drivers has significant consequences for DNSPs at the extreme ends of the spectrum of network types in the diverse Australian DNSP group.[145]

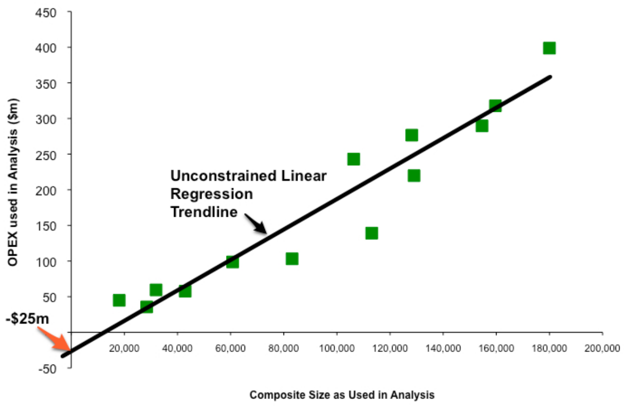
Huegin also raises broader concerns with the CSV framework as a tool to inform judgements on relative efficiency. It notes that the application of linear regression analysis to compare DNSP cost assumes that returns to scale are constant, that fixed costs will change with scale at the same rate as variable costs, and that these costs are homogenous. EnergyAustralia notes that the CSV framework relies on simplifying assumptions that do not reflect the individual circumstances of EnergyAustralia.

Specifically in relation to Wilson Cook's CSV analysis, Huegin notes that the unadjusted regression analysis produces anomalous outcomes. For instance, the regression line intercepts the y-axis at a negative value. This implies that DNSP costs are negative up to a certain scale when fixed costs in businesses are positive in reality. Huegin comments that this demonstrates the inadequacy of the regression line used in Wilson Cook's analysis and that it cannot be used as a representative industry benchmark of operating cost.

Wilson Cook's unadjusted CSV regression line is graphically represented in Huegin's report and is re-produced in Figure 9.1 below.[146] In addition to the negative intercept at the y-axis, Huegin also notes that the operating cost data points in Wilson Cook's analysis cannot be compared and averaged through regression. It found that if anything, the cost and scale data illustrates how each DNSP is different to the average.

[145] Huegin Consulting Group, *EnergyAustralia's regulatory proposal review (opex)*, January 2009, p24, (Attachment 9A)
[146] The graph is based on information contained in Wilson Cook's CSV analysis provided to EnergyAustralia by request from the AER. The graph is set out on p23 of Huegin's report at Attachment 9A.

Figure 9.1 Wilson Cook's unadjusted CSV analysis



Huegin also notes that Wilson Cook adjusted the regression analysis to force the regression line through the y-intercept at the value of zero. Huegin notes that constraining one end of this line by setting an intercept at the y-axis changes the gradient of the regression line and therefore the relationship between size and cost. The adjustment made by Wilson Cook implies that the fixed cost associated with Australian DNSPs approaches zero for the smallest of DNSPs and increases at a constant rate with increasing scale. This effectively renders all costs variable and is contrary to well established theory that natural monopolies have high fixed costs.

Huegin notes other instances where Wilson Cook applied poor judgement in applying the CSV analysis. For instance it notes Wilson Cook's 'intuitive' modification of the CSV function by replacing energy with peak demand as one of three key variables. Huegin states that Wilson Cook has provided no evidence that peak demand is a more appropriate determinant of cost in this context. Further, Wilson Cook showed no evidence that it had considered whether the model still held following this fundamental adjustment, or whether the new variable of demand might now correlate with other variables in the model such as customer numbers.

Huegin also raises concerns with the statistical significance of the data set used by Wilson Cook and its subsequent analysis. Huegin notes that the data set draws on only 11 data points, and that observations of future relative efficiencies were based on an even smaller sample size of the four NSW and ACT businesses. Given the implications of the recommendations made by Wilson Cook arising from this analysis, Huegin does not believe the sample is sufficiently large to provide statistically significant or definitive results.

Huegin's advice is that there are significant methodological weaknesses in the CSV approach generally. In addition to these limitations, Huegin highlights significant concerns with Wilson Cook's application of the tool. EnergyAustralia notes that Wilson Cook:

- Failed to consider and make variations for the network type, age, cost allocation and accounting policies of the businesses. This is despite Wilson Cook's acknowledgment that age is a significant driver of maintenance costs.[147]
- Adjusted the regression line to overcome anomalies in the uncorrected regression analysis, without considering the implications of such modifications.
- Modified the variables in the model based on 'intuition' and without any evidence.

Despite these deficiencies, Wilson Cook appears to have drawn definitive conclusions from this analysis and sought to generate further analysis using a bottom-up approach to confirm the findings.

Huegin's analysis demonstrates that Wilson Cook's benchmarking analysis should not be given any weight by the AER in determining whether step change expenditure is prudent and efficient.

EnergyAustralia has reviewed the application of Wilson Cook's CSV analysis to the other NSW and ACT DNSPs and notes that it produces anomalous results for some businesses in the sample. For example, Wilson Cook's CSV analysis indicates that ActewAGL's operating expenditure was 20 per cent above the industry norm and that it should therefore be reduced. However, this was 4 per cent lower than ActewAGL's operating expenditure allowance in its 2004-09 regulatory determination.[148]

This recommendation for ActewAGL's operating expenditure was not consistent with the AER's guiding principle applied in assessing the efficiency of base year costs which was set out in its draft distribution determination for NSW DNSPs[149]:

> the AER considers that where the proposed base year actual expenditure is close to or less than the efficient allowance provided in the previous regulatory determination, it is reasonable to accept the efficient base year as an efficient starting point for forecasting.

The AER noted that its guiding principle was one consideration in forming a view not to adjust ActewAGL's base year costs to account for Wilson Cook's CSV analysis. An implication of the AER's decision is that the AER was concerned that anomalies in the CSV analysis meant that it could not rely on it and accordingly it applied its own judgement in its application of this analysis to ActewAGL. The AER should also have tested the analysis before giving weight to the analysis for EnergyAustralia. The AER's failure to test Wilson Cook's analysis has led to errors in its assessment of EnergyAustralia's operating expenditure forecast.

In summary, the AER should not rely on Wilson Cook's top down analysis to form a view that EnergyAustralia's forecast operating expenditure is not at an efficient level. EnergyAustralia has provided substantive evidence which suggests Wilson Cook's analysis contains several methodological weaknesses and cannot be considered robust analysis on which to base substantive reductions to operating cost forecasts.

Wilson Cook's own criteria for step changes do not reflect the operating expenditure criteria

Following development of its CSV analysis, Wilson Cook turned to a more detailed assessment of operating costs. For EnergyAustralia, this comprised of consideration of the three

[147] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008,, Volume 2, p50.

[148] AER, *Draft decision: Australian Capital Territory, Distribution determination, 2009-10 to 2013-14*, November 2008, p90

[149] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p596

9-11. Operating expenditure
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cost adjustments applied by EnergyAustralia in deriving its forecasts for the 2009-14 period.

Wilson Cook did not assess the adjustment to take account of real cost movements as it considered it was not expert in this area and therefore referred the assessment to the AER.[150]

Wilson Cook's bottom up analysis concentrated on workload adjustments and step change adjustments.

Its method of assessing expenditure driven by step changes was to:

- Formulate its own criteria of step change as "a cost (that) ought to relate to a fundamental change in business environment arising from outside factors or be offset by cost efficiencies in other areas".[151]
- Consider whether the proposed operating expenditure item met this definition (without reviewing each cost category or cost item individually).
- Find that EnergyAustralia's forecast operating expenditure step changes are mostly the result of business decisions and not decisions made in response to external factors (controllable expenditure) and then make the simplifying assumption that such expenditure would be off-set or should be off-set by efficiencies in other areas.
- Recommend that all step change forecast expenditure items be removed except for those relating to apprentices, self insurance and regulatory resets, in effect on the basis that these were the only uncontrollable step changes.

EnergyAustralia is concerned that Wilson Cook began its assessment of step changes by applying a definition of step change that was not consistent with that applied by EnergyAustralia in its forecast, and one that was too narrow to accurately reflect the operating expenditure criteria in the Rules.

[150] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 1, p10-11

[151] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 2, p51

The term 'step change' is not used in the Rules or the regulatory framework more generally. EnergyAustralia's expenditure driven by 'step changes' merely reflects a forecast of expenditure on the basis that current year expenditure may not provide a reliable estimate of likely future expenditure as it does not (or does) include expenditure on items that will be prudently required (or not required) in the future. These expenditure items must be considered on the merit of the individual cost items. The criteria for accepting these costs must reflect the operating expenditure objectives and criteria in the Rules.

The Transitional Rules are clear (at clause 6.5.6(c)) that the AER must assess whether EnergyAustralia's forecast of operating expenditure reasonably reflects the efficient costs of achieving the operational expenditure objectives and reflect the costs that a prudent DNSP, in the circumstances of the individual DNSP, would require to achieve the objectives.

Wilson Cook failed to analyse the forecast of specific expenditure items and failed to assess the costs using the correct decision making criteria. Instead, Wilson Cook formulated its own criteria, which reflects an inappropriately narrow and simplistic interpretation of the Rules. Further, it misapplied its own criteria by failing to properly identify operating expenditure items that were not controllable, that is they resulted from other changes.

Focussing its definition on tangible customer benefits or actual cost reductions, Wilson Cook:

- assumed that such benefits or cost reductions were not otherwise reflected in EnergyAustralia's proposal;
- did not consider legitimate costs that a prudent business may incur in delivering outcomes other than cost reductions or improved customer outcomes.

A prudent business will invest to reduce risk which typically does not result in a tangible change to the product or service being sold, and does not reduce costs in the short term. In fact, investments to reduce risk add to business costs, at least in the short term, but are nevertheless prudent and efficient because they generate other non-cost benefits.

EnergyAustralia's investment in IT is a particularly good example of investment that addresses risks but does not lead to a reduction in costs in the short term or result in a change to the product. Despite not meeting Wilson Cook's criteria, such investment is undeniably prudent and should be undertaken by EnergyAustralia to protect its customer and asset information. IT investment is discussed in more detail in section 9.2.4.

Not only were Wilson Cook's criteria incorrect, the criteria were formulated after EnergyAustralia had submitted its proposal. From a procedural fairness perspective, EnergyAustralia had no knowledge that the AER or its consultant would test 'step changes' based on criteria that have no basis in the decision making framework in the Rules. We had no opportunity to make submissions addressing the appropriateness of those criteria. .

Furthermore, the AER's terms of reference did not require Wilson Cook to assess, or formulate criteria, for accepting costs driven by step changes. Wilson Cook was requested to assess the actual expenditure items - which it did not do.

Further, Wilson Cook did not test whether the step change expenditure could be offset by cost efficiencies in other areas, despite this being an element of its stated criteria. This is clear from Wilson Cook's statement that[152]:

> We did not consider that any of the step changes listed in the table (table 9.6 of its report) met the test of being necessitated by a fundamental change in business activity due to factors outside the control of the business.

The lack of clarity of Wilson Cook's approach is reflected in the AER reformulation of the Wilson's Cook criteria, concluding that a step change in operating expenditure should:

- Deliver a benefit to the customer in terms of the product delivered or to the business in terms of efficiency.
- Be non-recurring in nature or relate to a fundamental change in the businesses arising from outside factors.

The AER's reformulated criteria do not reflect the assessment process or stated criteria applied (or purported to be applied) by Wilson Cook. There is no evidence to indicate that Wilson Cook examined whether the step change delivered a benefit to the customer of business in terms of efficiency. That is, the criteria identified by the AER were not used by Wilson Cook to inform its findings on step changes. If the AER decision to rely on the Wilson Cook report is premised on an assumption that Wilson Cook undertook this analysis, then the decision is incorrect.

In summary, Wilson Cook assessed the step change inconsistent with the basis on which they had been included by EnergyAustralia in its proposal, and in doing so misapplied the operating expenditure criteria in the Rules, leading to conclusions and recommendations that were flawed. The AER, by accepting Wilson Cook's recommendation on the criteria has endorsed a definition of step change that is not consistent with the Rules.

Wilson Cook did not undertake a robust assessment of the step changes to sufficiently inform its findings

EnergyAustralia notes that Wilson Cook's "bottom up" review of step changes is not sufficiently robust to base an opinion on the prudence and efficiency of the expenditure.

Wilson Cook did not give adequate consideration to the material provided by EnergyAustralia which clearly identified and explained the reason for each individual step change. It is clear from Wilson Cook's statements that it did not review individual step changes.[153]

Not only did Wilson Cook apply a definition that was too narrow, it did not apply its own definition consistently to expenditure driven by step changes within EnergyAustralia's proposal. For example, Wilson Cook removed expenditure relating to external obligations such as land taxes, council rates, water rates, vendor licences for IT, and payments to the Energy and Water Ombudsman. These costs clearly meet Wilson Cook's definition of step changes being externally imposed.

Huegin also noted that Wilson Cook's method of assessment did not review individual step change categories and implicitly

[152] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 2, p54 and 59.

[153] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 2, p54 and 59.

ignored certain cost drivers and benefits. Huegin found that even using Wilson Cook's own criteria of step change (which it did not consider valid), only 12 of the 44 proposed step changes did not meet Wilson Cook's criteria.[154]

The inconsistent or non application of its own criteria of a step change, and the simplifying assumptions built into it, suggest that it was not intended to provide an independent basis to review EnergyAustralia's proposed expenditure, but was simply intended as a quick check test to support a conclusion that had already been formed from its top down analysis.

That is, it appears that Wilson Cook's bottom up analysis is focused on supporting its top down CSV analysis. This would appear to be the case given Wilson Cook's simplifying conclusion that step change expenditure should be offset by cost efficiencies.

Wilson Cook's recommendations to remove almost all step changes (those it considered to be in effect controllable by the business) effectively equates the value of the step change adjustments with the potential efficiency gains that Wilson Cook believes EnergyAustralia can achieve during the period. This high level assumption is not supported by detailed analysis or evidence. As mentioned above, Wilson Cook admits it has not assessed each of the step changes in detail. It would only be a matter of chance that the step change and the value of efficiencies are equal. Wilson Cook's assumption is in effect that the two were of similar sizes (and further assumed that no account for those efficiencies was otherwise reflected in EnergyAustralia's proposed forecasts). The result was that its bottom up analysis conveniently then supported its own unsound application of the CSV.

It is poor regulatory practice, and not consistent with the Rules to rely on a top down analysis undertaken by consultants without undertaking further analysis to understand the drivers for the outcomes of the top down analysis. This was noted by Huegin:[155]

> Benchmarking should only be used in conjunction with bottom-up analysis - such that the differences in cost can be investigated for unique circumstances that may drive those differences. This level of analysis is not evident in the AER's assessment of EnergyAustralia's cost efficiency.

EnergyAustralia has provided evidence to demonstrate that Wilson Cook's benchmarking analysis was not based on a reliable methodology. Further, Wilson Cook itself makes clear that they did not undertake a detailed examination of the expenditure that would be required to understand the drivers of the benchmarking outcomes.

In relation to step changes, Wilson Cook developed and applied its own criteria for accepting expenditure driven by step changes, which is too narrow to accurately reflect the decision making criteria in the Rules. And, as discussed above, rejected forecast costs for step changes that met its own criteria.

In summary, EnergyAustralia considers that the lack of rigour applied by Wilson Cook in its so called 'bottom-up' assessment, and the errors in its understanding and application of the CSV analysis used in its top-down assessment, make its conclusions incorrect. Furthermore, Wilson Cook's conclusions are not consistent with the Rules. The AER should not rely on Wilson Cook's advice and should re-examine the material provided in EnergyAustralia's June 2008 proposal and the additional information provided in this submission.

9.2.3 Additional material to demonstrate prudency and efficiency of step changes

EnergyAustralia considers the detail provided in support of its operating expenditure forecast outlined in its June 2008 proposal was sufficient to demonstrate the prudence and efficiency of that forecast. However, in light of the failure to properly assess EnergyAustralia's forecast methodology, we have provided additional material to demonstrate the prudence and efficiency of step change expenditure specifically.

Huegin undertook a detailed review of EnergyAustralia's proposed step changes to assess whether the expenditure reasonably reflects the operating expenditure criteria in the Rules. This is set out in sections 3-6 of Huegin's report at Attachment 9.A.

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[154] Huegin Consulting, *EnergyAustralia's regulatory proposal review (opex)*, January2009, p18

[155] Huegin Consulting, *EnergyAustralia's regulatory proposal review (opex)*, January2009, p24

Huegin's assessment tested the validity of the step change by reference to EnergyAustralia's ability to influence each cost component in the 2009-14 regulatory period and the impact on the business if costs driven by step changes are rejected. This approach was used to determine two things:

- to assess whether the costs were prudent and justifiable;
- to assess whether the costs, if rejected, could be removed from the operating base. If these costs could not be removed, cost savings would have to be sourced from other business expenditure that had been accepted by the AER as being prudent.

Huegin's formal framework for assessment was based on a modified application of the ISSR Framework. This framework categorises expenditure into four categories:

- Inherent costs – costs that are beyond the ability of the business to change;
- Structural costs – costs borne due to economic influence or historical events;
- Systemic costs – costs that result from business rules and policies; and
- Realised costs – those resulting from work and labour force management practices.

By assessing the ability of a business to control costs, Huegin can identify areas of expenditure that could be influenced by management decisions and could be the source of future efficiencies. The ISSR framework is a useful tool to apply within the regulatory framework. The regulatory framework incentivises businesses to reduce costs and thereby beat benchmark returns where possible. The ISSR framework identifies where businesses may look to source those efficiencies. By using the ISSR framework, a regulator can focus its attention on the areas where efficiencies can be achieved and avoid detailed scrutiny of costs that are inherent to the business and would be faced by any DNSP operating in similar circumstances.

To apply the ISSR framework in practice, Huegin assessed each element of incremental operating cost driven by a step change and rated each against the following criteria:

- the level of confidence in the accuracy of the cost estimate;
- the probability of the cost being realised by EnergyAustralia;
- the level of control that EnergyAustralia has over the expenditure; and
- the consequence of not paying the proposed expenditure.

Huegin used a detailed scoring system to assess each step change against these criteria. The relative rating against each of these four criteria was then used to determine each cost element's position within the ISSR framework (i.e. whether the cost, if rejected, could be avoided or whether the cost was inherent and therefore could not be avoided).

Huegin found that 34 per cent of step change expenditure related to inherent costs. These are the unavoidable costs that any prudent DNSP operating in similar circumstances to EnergyAustralia would incur and therefore should be regarded as valid increases in operating expenditure. The rejection of costs in this category will result in unforeseen budget cuts in other areas as these costs will be incurred by EnergyAustralia regardless of the outcome of the regulatory reset.

Huegin found that 40 per cent of the step change expenditure related to structural costs. These are costs that are difficult to avoid and should only be rejected if a sound reason is found to support that conclusion. It is most likely that costs in this category will be incurred by EnergyAustralia regardless of the AER's determination.

Huegin noted that the third category of systemic costs generally arise from management decisions and hence should be reviewed for the benefit of customers and the business. It found that 18 per cent of the step change expenditure was systemic costs.

Finally, Huegin found that 9 per cent of expenditure driven by step changes was on realised costs. It noted that such costs should be carefully reviewed for validity and accepted as valid costs if a clear and unambiguous link to customer benefit or cost efficiency (outweighing the ongoing cost) can be established.

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The results of Huegin's analysis is set out in Figure 9.2 below.[156]

Figure 9.2 Huegin's assessment of step change expenditure against the ISSR framework

Based on this analysis, Huegin concluded that when each of the rejected step changes are reviewed at the individual cost component level[157]:

- 76 per cent of the total value of step change expenditure is warranted, is accurately forecast, and is difficult to influence and/ or has significant consequences.
- 8 per cent require further investigation as to the magnitude of the cost but there is sufficient evidence to indicate that the cost is warranted.
- 16 per cent of costs required further investigation as to the underlying reason for the increase.

Huegin's assessment identified a total of 23 per cent of the step change expenditure (i.e. $70 million) that could be reviewed for future efficiency. These costs driven by step changes can be influenced by management decisions, but are not by definition, imprudent or inefficient expenditure.

If costs totalling more than $70 million are rejected, Huegin has demonstrated that the AER will force EnergyAustralia to reduce expenditure in areas that it has already assessed as being prudent and efficient in order to meet unavoidable or necessary costs. This outcome would not be consistent with the Rules.

Huegin's analysis identifies the areas where efficiencies *may* be identified. However, it notes that these costs may be unavoidable and therefore should be subject to further detailed review. It considered that the level of efficiencies available within the 5 year regulatory period would certainly be less than $70 million.

Importantly, Huegin has demonstrated that if these costs are removed in their entirety, without a detailed assessment, it is possible that the AER could reject costs that are prudent and efficient.

EnergyAustralia considers that the analysis undertaken by Huegin provides an appropriate method by which to identify areas where further investigation of expenditure should be focussed. Most importantly, Huegin has provided additional evidence to indicate that most, if not all of EnergyAustralia's incremental increase in forecast operating expenditure driven by step changes is prudent and efficient.

The AER should take into consideration Huegin's rigorous, transparent and consistently applied analysis. The analysis has been undertaken at a detailed level with reference to EnergyAustralia's supporting information and Huegin's own analysis is supported by detailed attachments outlining its assessment process, considerations and scoring system for each individual step change.

Huegin's analysis implicitly recognises the limitations of benchmarking and specifically considers the ability of a business to control costs in its own circumstances.

Huegin's analysis does not rely on the simplifying assumption that efficiencies will be achieved in areas where investment decisions have already been made and approved by the AER.

The AER should change its assessment of EnergyAustralia's operating expenditure and note that:

- Step changes as identified by EnergyAustralia are a valid method to forecast, and in many cases, are directly linked to capital expenditure approved by the AER;

[156] Huegin Consulting, *EnergyAustralia's regulatory proposal review (opex)*, January2009, p124
[157] Huegin Consulting, *EnergyAustralia's regulatory proposal review (opex)*, January2009, p125

- Efficiencies can only be realistically achieved in areas where costs can be influenced by management decisions (i.e. systemic or realisable costs); and
- At most, the costs that can be influenced by management represent $70 million of the expenditure driven by step changes. However, some of the costs are not by definition imprudent or inefficient and therefore would need to be reviewed in more detail. .
- Reductions in operating expenditure of $303 million as applied by the AER in its draft determination will inevitably lead EnergyAustralia to reduce expenditure on investments that have been assessed by AER as being prudent and efficient and consistent with the Rules.

9.2.4 Additional material to demonstrate EnergyAustralia's total forecast operating expenditure satisfies Rule requirements

The AER's draft determination notes and implicitly accepts Wilson Cook's comment that:

> The application by EnergyAustralia of workload escalators as well as step changes did not include any consideration of business efficiency[158]

Huegin's detailed review of step change expenditure demonstrates that this premise is flawed. The individual step changes are, for the most part, unavoidable costs that management cannot influence.

Given that the step change expenditure is efficient and prudent, the only other possible reason for reducing the forecast operating expenditure evident in Wilson Cook's report is that[159]:

> … we consider that the large investment proposed in IT systems and property should lead to improvements in business efficiency and reductions in opex.

We agree with this comment. Business efficiency and better use of internal resources is a key consideration when investing in new technologies and property. We have incorporated these considerations in our forecasting process.

We disagree however with Wilson Cook's comments that[160]:

> We could not find any indication that EnergyAustralia has allowed for specific improvements in organisational efficiency or productivity in its proposal. It advised us that productivity changes had been allowed at a "sector" level in the forecast of future labour costs.

Wilson Cook was correct in identifying that EnergyAustralia did not apply any high level, arbitrary adjustments to the estimate of operating expenditure to reflect a notional forecast of business efficiency (that is not quantified or substantiated.

However, the Rules do not require EnergyAustralia to do this. The Rules require us to provide a total forecast of operating expenditure required to meet the operating expenditure objectives. We have done this and shown our processes to achieve the operating expenditure objectives based on a detailed and transparent methodology and established with prudent and efficiency considerations.

We reiterate our approach to developing an efficient forecast in the June 2008 proposal in the sections below.

Wilson Cook and the AER did not provide any indication that they assessed the material in EnergyAustralia's June 2008 proposal which addressed these issues. The June 2008 proposal demonstrates that the *total* forecast operating expenditure reflects the operating expenditure criteria in the Rules.

Section 11.4 of our June 2008 proposal demonstrates how the forecast meets the operating expenditure criteria, particularly how EnergyAustralia considered and incorporated efficiencies

158 AER, *Draft decision: New South Wales: draft distribution determination 2009-10 to 2013-14*, November 2008, p175

159 Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 2, p51.

160 Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 2, p51.

in its operating expenditure forecasts. We demonstrated that our forecast process considered:

- efficiency of the total forecast expenditure distinct from the efficiency of each individual component of the expenditure (section 11.4.4 of the June 2008 proposal); and
- the efficiency of the forecast in a medium and long term context (section 11.4.6 of the June 2008 proposal).

Efficient forecasting process

EnergyAustralia noted in its proposal that it sought independent advice from NERA as to how the forecast of capital and operating expenditure should be approached to demonstrate how the terms prudent and efficient contained in the Rules have been applied to the proposal in practice. The NERA report was included as Attachment 6.1 to the June 2008 proposal

An important element of NERA's advice was that a business's forecasting process is a key indicator of an efficient and prudent forecast[161]:

> Notwithstanding the fact that there are no external, objective factors that can be relied upon to demonstrate that a DNSP's expenditure forecast reflects efficient costs, there are some partial indicators that can be used to assess the efficiency of expenditure associated with specific items included within the forecasts. Demonstration by the DNSP that these aspects of its projected level of expenditure reasonably reflect efficiency, as well as having been derived as the result of a prudent process, provide comfort that the processes used to develop the forecasts overall are indeed prudent (and that the overall forecasts reasonably reflect efficient costs)..

EnergyAustralia demonstrated that its forecasting process could be relied on to establish an efficient forecast of future operating expenditure requirements. For instance, EnergyAustralia used the audited base year costs in 2006-07 to forecast future requirements. The AER noted that it was satisfied that EnergyAustralia's base year is representative of efficient expenditure from which to project its forecast operating expenditure requirements for the next regulatory control period.[162]

EnergyAustralia applied efficient real cost escalation, workload escalation and step changes to forecast future expenditure requirements. EnergyAustralia applied the workload escalators and step changes in a detailed and transparent manner to ensure that there was no double counting of costs. The AER and Wilson Cook did not find any instances of inappropriate double counting of step changes or workload escalators.

Further, the forecast process ensured a prudent and efficient forecast of costs by:

- applying workload escalators only to the variable costs of each cost activity;
- using productivity-adjusted real labour forecasts;
- adjusting base year costs for abnormal variations including a negative adjustment for storm event costs in 2006-07; and
- identifying saving offsets from the introduction of new technology, for instance from the retirement of old systems.

Huegin made the following comments on EnergyAustralia's forecast process based on its thorough review of step change expenditure items:

> Close inspection of the step changes, reveals that efficiencies and cost savings have been taken into account wherever those cost savings could be quantified.[163]

EnergyAustralia's forecast is based on a detailed assessment of costs and future cost drivers. It is therefore not appropriate to apply broad brushed and high level adjustments to demonstrate that considerations of efficiency have been taken into account.

This view was also expressed by Huegin based on its detailed review of the forecast process:

[161] NERA, *Economic Interpretation of clauses 6.5.6 and 6.5.7 of the National Electricity Rules,* 7 May 2008, p20.

[162] AER, *Draft decision: New South Wales: draft distribution determination 2009-10 to 2013-14*, November 2008, p596

[163] Huegin Consulting, *EnergyAustralia's regulatory proposal review (opex)*, January 2009, p11

> It is our opinion that this approach to modelling cost efficiencies is a more robust and reliable method than applying broad organisation wide productivity factors. [164]

Efficiency and productivity measures in EnergyAustralia's forecasts

EnergyAustralia's forecasts of expenditures factor in organisational productivity and efficiency improvements over the next regulatory period. This was made clear in our response of 8 August 2008 (Attachment 9B) to Wilson Cook's question regarding efficiencies in the forecasts.[165] We are concerned that Wilson Cook may have overlooked this response in forming its view.

Our response to Wilson Cook identified several areas where EnergyAustralia incorporated efficiency and productivity improvements in its forecasts. EnergyAustralia has incorporated these improvements to enable it to deliver a large scale investment program over the next 5 years. Some examples of efficiency improvements include:

- Design initiatives introduced into projects over the last 2 years and estimated to have saved approximately 5 per cent of project life cycle costs.
- Use of an enhanced suite of contracting arrangements with external partners which will free up internal resources and allow EnergyAustralia to deliver more with the existing employee base.
- Design and construct style contracts, which also enable a streamlined delivery of the investment program.
- Investment in IT and property (depots etc) that will improve staff capability.

EnergyAustralia's initiatives are aimed at improving the efficiency of internal resourcing allowing EnergyAustralia to deliver more with the existing employee base. It includes significant investment in IT to enable staff to work more efficiently.

Clearly, if we did not have these programs in place our operating costs would be more inefficient (we would have to employ more staff) but also imprudent (we would not deliver our capital program putting our compliance at risk).

The efficiency initiatives have been acknowledged and endorsed by Wilson Cook and the AER in respect of the AER's draft determination on capital expenditure. The AER noted EnergyAustralia's delivery strategy particularly with respect to increasing the capability of staff and outsourcing arrangements when making its considerations on the deliverability of the investment program.[166] Wilson Cook identified non-system capex as part of the measures that EnergyAustralia has taken to ensure that it is able to deliver the capex program:

> EnergyAustralia has recognised the need to increase its resources to deliver its proposed investment program and has taken measures to ensure that it is able to do so. In essence it proposes to increase the capability of its staff through the use of standard designs, advanced design software, network automation and the deployment of mobile computing; increase the work undertaken by contractors … and establish alliance agreements with private sector construction companies and consultants to undertake major projects under turn key style arrangements.[167]

Given the substantive information provided to Wilson Cook in respect to efficiency and productivity considerations in developing our forecasts, it is difficult to reconcile Wilson Cook's comments that the only indication of productivity in our proposal related to that "… allowed at a "sector" level in the forecast of future labour costs"

There is sufficient evidence to establish that the AER cannot rely on Wilson Cook's statement that it could not find any indication that EnergyAustralia has allowed for specific improvements in organisational efficiency or productivity.

[164] Huegin Consulting, *EnergyAustralia's regulatory proposal review (opex)*, January2009, p11

[165] EnergyAustralia, *Responses to Wilson Cook's questions of 8th August 2008*, Question 12

[166] AER, *Draft decision: New South Wales: draft distribution determination 2009-10 to 2013-14*, November 2008, p498.

[167] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 2, p40.

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Large scale investments in IT and reductions in opex

Perhaps a better understanding of Wilson Cook's concerns lie in its assessment of IT capital expenditure when it states:

> After considering these factors, we concluded that the expenditure on IT systems was reasonable without adjustment but noted that such investments should result in improved business efficiencies and operational cost savings. [168]

In this section we demonstrate that Wilson Cook's contention that large scale investments in IT lead to significant cost savings in operating expenditure is based on an incorrect understanding of the time period over which efficiencies are realised and how these efficiencies are accounted for.

EnergyAustralia has demonstrated that it considered efficiencies in its forecast process and has quantified them where possible. We considered it was not prudent to make further high level efficiency adjustment based on the potential benefits of investment in IT. This contrasts with Wilson Cook's view that such adjustments should be incorporated into forecasts.

Our forecasting processes indicate that the costs associated with a transitional phase of IT implementation can be relatively high. We certainly had no internal analysis that would suggest it would be prudent or efficient in our circumstance to reduce our forecast operating expenditure purely on the basis that IT investment is made in any particular year.

Failure to provide an adequate operating expenditure allowance, particularly during an investment phase, will threaten the ability of EnergyAustralia to meet its operating expenditure objectives. The fact that most of the step changes rejected by Wilson Cook are driven by capital expenditure means that their rejection also threatens the ability of EnergyAustralia to meet its capital expenditure objectives.

[168] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 2, p44.

In addition, the timing and treatment of efficiency benefits is a key consideration in assessing the adequacy of the operating expenditure forecast in the short term

To assess Wilson Cook's assertions that large scale investments should deliver reduced operating costs, EnergyAustralia engaged Concept Economics to provide advice about how operating efficiencies are achieved over time, and particularly during periods of high capital investment.

Concept Economics are experts in assisting major organisations to measure their productivity and to assess the scope for efficiency improvements. Concept's full report is set out at Attachment 9C.

Concept Economics noted that:

> One possible analysis is that high levels of capital expenditure, and the introduction of technological innovation would (all else being equal) justify lower operating cost forecasts and more aggressive assumptions on future productivity gains. This analysis relies on the narrow and basic applications of concepts of economies of scale and scope. Yet closer economic analysis and empirical evidence focused on the observed relationship between high capital investment in goods and services of the type that make up a large part of EnergyAustralia's non-system costs, suggests this approach may be misleading.[169]

Concept Economics reaches two very important conclusions[170]

- Without complementary investments (i.e. associated operating expenditure), core IT systems can fail to deliver benefits of investment for customers or to the business.
- Productivity gains driven by technology investments are not instantaneous but rather, a lag between the primary and complementary investments and those investments reaping efficiency gains is normal.

The advice provided by Concept Economics supports EnergyAustralia's view that a transitional phase of IT implementation would not immediately lead to a conclusion that a business can lower its forecast costs after IT investment

[169] Concept Economics, *Operating efficiencies in periods of high investment and technology change*, 9 January 2009, p1.
[170] Concept Economics, *Operating efficiencies in periods of high investment and technology change*, 9 January 2009, p10.

because the business becomes instantaneously more efficient. It also demonstrates that it would be imprudent to apply a high level efficiency adjustment given that there is a lag between investment and efficiency gains and that efficiency gains are not exclusive to a lower forecast of operating expenditure across the business.

Concept Economics advice also demonstrates that businesses in other industries recognise the long term value and benefits of investment in large scale investments in IT that go beyond a lower operating expenditure forecast. Concept Economics highlights Telstra's decision in 2005 to undertake a five year transformation process of its IT infrastructure. Concept noted that major decisions were made by Telstra to "increase the specific IT costs in the short term, in recognition of the long term value and efficiency benefits that would follow."[171]

As noted by both AER and Wilson Cook, EnergyAustralia has proposed, and had approved, a very large program of capital expenditure. The program is the largest to be undertaken by a DNSP over a five year period and represents a significant challenge to the business. EnergyAustralia is investing heavily in technologies that will facilitate this program of investment and the maintenance and management of the network into the future. EnergyAustralia knows that without this investment, its ability to deliver the capital program with forecast resources will be compromised.

Concept's advice shows that other companies facing similar investment challenges have invested in enabling technologies to facilitate delivery of large investment programs, in the knowledge that the program itself will deliver efficiencies in the longer term, and the enabling technologies will allow those benefits to be achieves as quickly as possible.

EnergyAustralia considers that the advice of Concept Economics provides a theoretical and empirical basis for supporting the prudence and efficiency of our forecast process.

Efficiencies from property and investment

Below we demonstrate the efficiency and prudence of our capital and operating forecast processes with reference to incorporating efficiencies from investment in IT and property. This process included consideration of short term and long term efficiencies, customer benefits and prudent risk management.

The key conclusions are:

- Our processes and methodologies were built with efficiency as a key consideration
- Efficiency in the circumstance of EnergyAustralia's business goes beyond and arbitrary reduction in overall operating costs
- Operating efficiencies will be medium to longer term.

Property

EnergyAustralia's property plan is partly driven by the need to do more tasks in the business to meet our regulatory obligations. For instance, EnergyAustralia is better situating depots to enable field staff to do more maintenance tasks. This frees up internal resources to do other work in the business.

Section 4 of Huegin's report demonstrated that the incremental operating costs associated with investment property (i.e. step changes) are driven by external factors and therefore are unavoidable.[172] Below we demonstrate that EnergyAustralia has also considered the business wide operating efficiencies resulting from these investments.

Property – short term efficiency

In the short term, EnergyAustralia has forecast a net increase in property related costs driven directly by higher costs being levied in the form of taxes, levies and rates. It is important to note that direct savings have been incorporated in to the forecast in areas such as maintenance.

[171] Concept Economics, *Operating efficiencies in periods of high investment and technology change*, 9 January 2009, p9.

[172] Huegin Consulting, *EnergyAustralia's regulatory proposal review (opex)*, January2009, p60-72

9-11. Operating expenditure
(continued)

EnergyAustralia's maintenance cost forecast for non-system property was based on an external dilapidation report undertaken by Davis Langdon, an external property expert. That report recommended a step up in maintenance activity (and therefore cost) in the short term to remedy the building maintenance backlog. After the backlog has been addressed, EnergyAustralia has forecast a step down in these costs as maintenance costs return to a steady level.

EnergyAustralia has not included any additional business wide adjustments for short term efficiency from property investment. The efficiency benefits from increased network property such as depots will only be possible when the property strategy is delivered. EnergyAustralia's total property holdings will expand incrementally over the regulatory period as new zone substations are built to replace old ones, and new, better situated depots are built to replace existing depots. In addition to this, the operating efficiency benefits of optimising depots (once built) will not be instantaneous and these benefits will be lagged.

Property – long term efficiency

In the longer term, the property strategy will deliver benefits to EnergyAustralia by better situating depot locations to enable field staff to access parts of the network more quickly, and thereby improve reliability performance and customer benefits.

Furthermore, cost savings are expected in the longer term driven by shorter travel times, which will give field staff more time to do maintenance tasks, and lower fuel costs due to shorter travel distances. This will increase the effectiveness of EnergyAustralia's maintenance expenditure by enabling existing staff to do more work, (i.e. increasing EnergyAustralia labour efficiency). However, these benefits will not be realised until the property strategy has been delivered. If operating expenditure is deducted in advance, the long term delivery of these benefits will be jeopardised.

Information technology

EnergyAustralia's IT operating expenditure was required to enable EnergyAustralia to meet its obligations under the Rules. The June 2008 proposal states that:

> The major strategic directions underpinning the proposed IT investments are:
>
> - A new Data Centre to manage data security;
> - Continued support for asset management, planning, maintenance and network control through implementation of iAMS (SAP based integrated Asset Management System); and
> - Extension of the EnergyAustralia work environment to mobile staff and service providers in the field. [173]

It is clear from this excerpt that reduced operating costs are not the only reasons a business would increase its investment in IT systems. In fact, these investment priorities reflect the circumstance of the business (i.e. the need to deliver a significant investment program in a relatively short time frame).

Data security is a good example of such an investment. Increasing investment requirements lead to increasing amounts of data and information required in the business. Security of data has benefits in terms of risk mitigation and avoided costs. It does not, of itself, produce efficiency (in a dynamic sense), but may over time avoid inefficiencies associated with loss of data and the consequences of poor investment decision making if data is lost.

The other two major strategic investments, iAMS and field computing, both have implications for costs and efficiencies in the short and long term. These issues of short and long term efficiencies and efficiency lags are considered in sections below.

IT – short term efficiency

EnergyAustralia's detailed cost build up makes it clear that IT investment requires complementary operational expenditure to derive the full benefit of the investment. Without this expenditure, IT systems would be purchased, designed and installed, but could not be operated or maintained. Rejecting the operating expenditure associated with IT investment makes the capital investment in IT of little value and destroys potential benefits of such an investment.

In compiling its forecast, EnergyAustralia explicitly considered the costs associated with transitioning from one IT system to another, and the fact that during the transition period, two IT systems are required to be operational. This results in higher costs during the transition period. EnergyAustralia also

[173] EnergyAustralia regulatory proposal, June 2008, p72.

considered the costs of training people to use new systems, the costs of securely managing the systems and ongoing licence and support fees. In the short term, IT costs are higher.

In terms of efficiency, EnergyAustralia predicts that the capability of staff will deteriorate in the short term until such time as they become acquainted with systems and the new capabilities. This is likely to be the case with field staff that may be utilising new on-line technologies for the first time.

IT – long term efficiency

Despite these short term costs, EnergyAustralia is committed to invest in systems to deliver long term asset management and business efficiencies.

To demonstrate the efficiencies to customers from our proposed IT investments, we asked Price Waterhouse Coopers (PWC) to examine a case study on the additional functionality of the Integrated Asset management Systems (iAMS). The purpose of the case study was to explain how EnergyAustralia's operating efficiencies have factored in future efficiency improvements. PWC's full report is set out at Attachment 9D.

In developing the case study, PWC reviewed the business case that EnergyAustralia prepared to obtain Board approval to undertake the expenditure associated with iAMS. PWC followed this up with consultation and discussion with EnergyAustralia representatives in the IT Strategy and architecture division. PWC found that:

PWC found:[174]

> The key advantage that EA anticipates from iAMS and the additional functionality being implemented is that it will increase integration with other systems such as EA's Geographic Information and Outage Management Systems. EA indicates that this integration will provide EA with a single source of asset data, improving EA's understanding of its network and the condition and maintenance needs of each asset. This should assist in improving future network planning by providing EA with a higher degree of confidence in its asset management decisions and enabling EA to potentially achieve more efficient outcomes from the trade-offs it makes between maintenance and replacement expenditure.

PWC noted that customers will benefit from the investment in the long term because EnergyAustralia will be able to make optimal decisions for asset replacement and be able to make replacement decisions backed by sound cost-benefit data. Thus, efficiencies in the way EnergyAustralia manages its network will be achieved leading to more efficient costs to customers over the long term.

PWC's observations on the long term efficiency are supported by Huegin's analysis. Huegin referred to evidence which suggest that the implementation of integrated asset management systems can deliver maintenance savings of up to 40 per cent over a period of 25 years. Huegin notes that realised cost efficiencies will be incremental and are unlikely to be realised until after the upcoming regulatory period.[175]

Importantly, PWC also found that:[176]

> EnergyAustralia's operating forecasts factor in anticipated efficiencies from rolling our iAMS and the operating costs would be higher without assumed gains from implementing iAMS.

PWC noted that delivering EnergyAustralia's capital without iAMS would have resulted in much higher facilities management costs from housing and supporting the hardware required to run the large number of databases (over 78) that existed prior to the rollout of iAMS. There would also be significantly higher capital and operating costs associated with migrating data to the central data centre.

PWC noted for example that significantly more support staff would be required if iAMS was not rolled out compared to the two additional full time equivalents (FTE) that EnergyAustralia has proposed. In other words, without the capabilities provided by iAMS, significantly more than two FTEs would be required

[174] PriceWaterhouseCoopers, *Case study: EnergyAustralia's approach to incorporating efficiency gains into operating expenditure forecasts utilising its Integrated Asset Management System*, January 2009, p4.

[175] Huegin Consulting, *EnergyAustralia's regulatory proposal review (opex)*, January2009, p53

[176] Price Waterhouse Coopers, *Case study: EnergyAustralia's approach to incorporating efficiency gains into operating expenditure forecasts utilising its Integrated Asset Management System*, January 2009, p6.

to provide similar levels of automation, functionality and reporting that can be provided by the iAMS system.

Summary

Throughout this section, EnergyAustralia has demonstrated that EnergyAustralia considered efficiencies as part of its forecast process. This included considering sectoral productivity adjustments, allowing for volume increases for only the variable element of costs and including any cost savings from investment.

In addition, EnergyAustralia identified specific business efficiencies that were incorporated into the forecasts of capital and operating expenditure. These measures are directed at improving staff capability to deliver the large investment program.

EnergyAustralia did not make high level adjustments to its operating expenditure forecast to account for short term business wide efficiencies from this investment. We noted that there are transitional costs when implementing large scale IT and property investment that may increase the short term costs of a business. In this regard, we noted the advice from Concept Economics that it would be imprudent to consider that efficiencies from these types of investment are instantaneous.

EnergyAustralia provided examples of property and IT to demonstrate that its processes consider cost efficiencies and that the realisable gains from such investment were in the medium to long term.

9.2.5 Summary of EnergyAustralia's submission to the AER's finding on step changes

In summary, there is compelling evidence to demonstrate that the AER erred in its reduction of EnergyAustralia's operating expenditure, particularly in relation to step changes. This is because:

- The AER did not assess the material that EnergyAustralia provided in the June 2008 proposal and instead adopted the conclusions of Wilson Cook without properly testing this advice. The material provided in our proposal demonstrates the prudence and efficiency of each individual step change and that the total operating expenditure forecast satisfies the operating expenditure criteria in the Rules.
- The evidence provided in this submission demonstrates that Wilson Cook's opinion was poorly prepared and cannot be relied on by the AER.
- The additional evidence from Huegin demonstrates that EnergyAustralia's step change expenditure items reasonably reflect the operating expenditure criteria in the Rules.
- EnergyAustralia provided material to the AER and Wilson Cook which demonstrated that EnergyAustralia incorporated business efficiencies into its forecasts. Further we demonstrated that our efficient forecast processes explicitly included efficiencies. This demonstrates that there is no level of overstatement in the total forecast operating expenditure and that the proposed amount reasonably reflects the operating expenditure criteria in the Rules.

9.3 Maintenance costs

The AER reduced EnergyAustralia's forecast of network maintenance expenditure by $54 million as recommended by Wilson Cook. This was based on:

- $12 million reduction based on Wilson Cook's finding that the relationship between age and maintenance in EnergyAustralia's maintenance model may be overstated.
- $24 million reduction based on information provided by EnergyAustralia on the 'year zero' values for the cost-age curves in EnergyAustralia's maintenance cost model and for correction of errors.

The AER's findings on network maintenance expenditure also included a reduction of $19 million for step change expenditure relating to publications data and third party insurance costs.

EnergyAustralia's comments

EnergyAustralia does not agree with the AER's findings on our forecast of network maintenance expenditure.

In particular, the AER should not rely on Wilson Cook's advice that the relationship between age and maintenance in EnergyAustralia's maintenance model may be overstated.

Wilson Cook's advice is inconsistent with the views of engineering experts and does not take into account the theoretical basis for the model. Further, Wilson Cook's regression analysis of the relationship between age and maintenance costs of New Zealand utilities is flawed and should not be relied on by the AER. We also provide additional material from Sinclair Knight and Merz to demonstrate the prudence of the assumptions in the maintenance model.

EnergyAustralia notes that it does not agree with the AER's findings on step changes for publications data and third party insurance costs. Our comments on the AER's findings on step changes are set out in section 9.2 of this revised proposal. We note that the review of step changes undertaken by Huegin and submitted at Attachment 9A of this submission.

Maintenance costs increase exponentially with the age of the asset

EnergyAustralia's approach to forecast maintenance requirements was set out in section 9.6 of the June 2008 proposal and was supported by documentation attached to the proposal. This material included:

- EnergyAustralia's asset management strategy (Attachment 9.3 of the June 2008 proposal)
- A report by SAHA on "Electricity distribution business operational expenditure review" (Attachment 6.2 of the June 2008 proposal)
- Supporting documentation attached to the June 2008 proposal including the maintenance model description" and "Opex model documentation".[177]

As stated in the June 2008 proposal, EnergyAustralia used a top-down approach to forecast maintenance expenditure requirements. This was the same approach used in our 2004 distribution and transmission proposals. The top down methodology uses a model to forecast maintenance expenditure. The model assumes a relationship between the age and maintenance costs of assets.

In order to confirm the credibility of the outcomes from the top-down approach, EnergyAustralia also undertook a bottom-up assessment of its maintenance requirements. This involved analysis of historic numbers of completed planned inspection tasks and calculation of the associated costs per task. This cost was then compared to the actual recorded costs.

As part of its June 2008 proposal (Attachment 6.2), EnergyAustralia also engaged SAHA International to benchmark asset management performance with a particular focus on maintenance. SAHA concluded that EnergyAustralia's maintenance practices were relatively efficient. SAHA noted that:[178]

> EnergyAustralia meets or exceeds best practice thresholds for asset management practices. (EnergyAustralia's) current asset management regime ensures that maintenance programs are optimised for both cost and asset performance.

The model used in the top down approach derives 'cost-age' curves based on the weighted average life of particular asset types. This enables EnergyAustralia to forecast maintenance requirements for asset types based on the weighted average life of the asset type. A key assumption in developing 'cost-age' curves is that maintenance requirements increase exponentially with the age of an asset.

The robustness of this assumption is a matter addressed in the AER's draft distribution determination. The AER accepted Wilson Cook's advice regarding the relationship between age and maintenance stated by EnergyAustralia is not robust and may be overstated. It appears that the AER did not test Wilson Cook's analysis or undertake additional analysis of the model documentation submitted by EnergyAustralia in the June 2008 proposal.

The AER should not give weight to Wilson Cook's conclusions without considering the material in support of EnergyAustralia's model. As explained below, Wilson Cook's conclusions should not be relied on for the following reasons:

[177] This was set out in DVD 2 of the proposal.

[178] SAHA, *Electricity Distribution Business Operational Expenditure Review*, 4 April 2008, p28.

9-11. Operating expenditure
(continued)

- EnergyAustralia's model is based on expert engineering analysis undertaken by SKM in 2003 and was used to develop EnergyAustralia's 2004 regulatory proposals.
- Additional material provided by EnergyAustralia in this revised proposal supports the assumption that maintenance costs increase exponentially with the age of an asset.
- Wilson Cook does not provide sufficient evidence or analysis to support its conclusions.

Our submission draws on the advice of Sinclair Knight Merz (SKM) who has been engaged by EnergyAustralia to respond to the AER's decision on maintenance expenditure. SKM developed EnergyAustralia's maintenance model for our regulatory proposal in 2003.

SKM's advice provides background information on the approach it used to develop the model and also demonstrates the theoretical basis for assuming an exponential relationship between the maintenance costs and age of an asset. SKM also critically assess Wilson Cook's findings, concluding that its analysis is not robust. SKM's full report is set out at Attachment 9Eof this revised proposal.[179]

In Appendix F of its report, SKM outlines its experience in the industry. SKM is highly experienced in undertaking high level modelling, estimating, forecasting and analysis of electricity distribution networks. It notes the following areas where it has provided advice in the past:

- asset management policy, procedures and practices;
- asset age profiling and refurbishment and replacement planning; and
- asset and system performance modelling.

EnergyAustralia's model is robust

EnergyAustralia's model is consistent with our approach to forecast maintenance requirements in our proposals for the 2004-09 regulatory determinations. We note that IPART and ACCC did not raise any concerns with the robustness of the model during their reviews of our distribution and transmission regulatory proposals.

The model was originally developed by SKM in 2003.[180] In section 3 of its report, SKM provides background on how it developed the model. SKM notes that the model took into account operating maintenance cost data that EnergyAustralia had collected by asset class for the three years prior to SKM undertaking the analysis.[181] SKM states that the cost database facilitated a more refined level of fault and maintenance cost analysis and whole of life costing for each class of asset. SKM however notes that it did not draw any conclusions from the three years of EnergyAustralia's data.

SKM comments that Wilson Cook did not fully describe the process that SKM went through in determining the likely profile of curves. SKM constituted a panel of highly experienced ex-industry engineers with many years of experience in both transmission and distribution operations and maintenance. Section 3.1 of SKM's report provides further detail on this approach.

SKM reviewed the differences between the model used for the 2004-09 determination and the model used by EnergyAustralia for the June 2008 proposal. SKM notes that the version of the model used in EnergyAustralia's June 2008 proposal retains the primary underlying assumptions of the 2003 model. SKM also found that the enhancements made by EnergyAustralia such as consideration of a moving average age for the different asset categories and adjustments to include actual recorded expenditure make the outputs generated more reliable and credible.

We consider that the model was developed by engineers with expertise in the areas of asset management and provides a robust method to forecast maintenance expenditure for the next regulatory period.

[179] SKM, *Response to Wilson Cook Commentary on O&M/ Age Profile modelling*, 5 January 2009.

[180] EnergyAustralia provided documentation to Wilson Cook and the AER relating to SKM's 2003 report. This was provided on 8 August 2008 in a response to an email question.

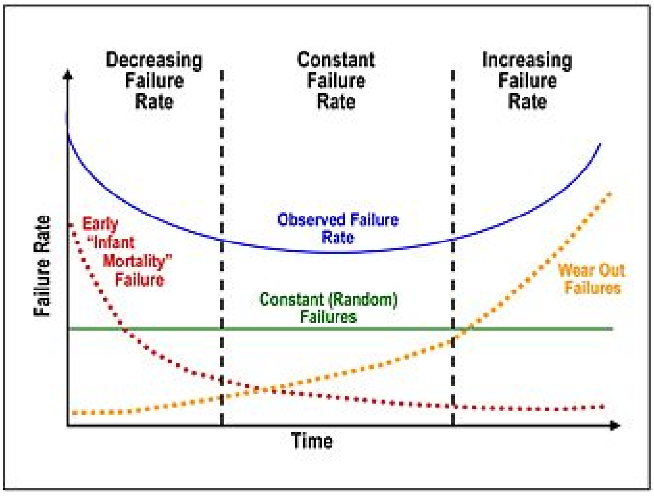
[181] For instance, SKM noted that the cost data was collected for distribution overhead and underground assets.

Additional evidence from SKM on why the curve should be exponential

In section 4 of SKM's report at Attachment 9E, SKM provides more information on why the 'cost-age' curve should be exponential. This is to specifically address Wilson Cook's comments that: "the analysis begs the question… why the curve should be exponential" and "exponential growth in expenditure of any sort occurs in reality".[182]

SKM notes that its original choice of an exponential relationship to approximate the likely impact of ageing assets on operating costs was based on a review of reliability and failure theory. In particular, traditional reliability theory derives a "bathtub curve to describe the hazard function for component failures. Figure 9.2 is re-produced from SKM's report below to provide an illustration of the theoretical basis for the 'bathtub' shaped curve. [183]

Figure 9.2 Bathtub curve



The bathtub combines three type of cost-age relationships including early failures ("infant mortality"), constant random failures and wear out failures. SKM notes that modern quality control techniques, factory test regimes and commissioning checks have tended to reduce early failures to the point where they can be considered negligible. Consequently, SKM did not allow for the 'early failure' section of the curve when calibrating the opex age curve in its 2003 model.

Importantly, SKM notes that the relationship most commonly used to describe wear out failure is exponential, or some related variation[184] which ultimately drives the exponential shape of the cost-age curve.

SKM also notes that its model describes the inspection, testing, routine and corrective maintenance costs of DNSPs. SKM's experience suggests that these costs are strongly correlated with age because increasing inspection and maintenance regimes are considered prudent for older assets.

In contrast, SKM notes that a linear function results in counter-intuitive outcomes. A linear curve implies a declining percentage increase in costs as age of the asset increases. The implication is that the older assets are, the lower the relative increase in their maintenance costs. SKM is not aware of any such rigorous or published theory of reliability. This leads to note that: [185]:

> "if anything, SKM would expect a lower rate of change for newer assets, increasing with age. The exponential hazard function (uniform rate of change) is closer to this than the linear (declining rate of change)."

In addition to the theoretical basis of an exponential function, SKM notes that the operational characteristics of distribution networks also support its assumption. For instance, SKM observes that there are several generations of technological developments of each type of asset on most networks. Older sub-components of an asset not only exhibit characteristics of ageing and degradation, but are also of a design that are inherently higher in maintenance, and comprise materials that

[182] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 2, p 50.

[183] SKM, *Response to Wilson Cook Commentary on O&M/ Age Profile modelling*, 5 January 2009, p10.

[184] SKM noted for instance, a Weibull curve with a shape factor close to that describing an exponential.

[185] SKM, *Response to Wilson Cook Commentary on O&M/ Age Profile modelling*, 5 January 2009, p11.

9-11. Operating expenditure (continued)

are inferior to newer equipment. In addition, spare parts become unavailable and must be scavenged from "system spares" (the same type of equipment that has already been taken out of service), often requiring refurbishment.

Further, some sub-components will be kept in service well beyond what would be considered their economic life, in order to keep the whole assembly operational. In SKM's view, all these factors act to increase maintenance costs of the assets in service, especially assets which are older than their expected economic life.

SKM also identifies condition monitoring and preventative maintenance as another practical consideration that supports an exponential function for cost-age curves. It observes that Australian DNSPs are implementing condition monitoring of various asset classes in an attempt to defer capital expenditure on new assets and replacement of existing assets. Some of the rapidly increasing maintenance costs are associated with the testing and condition assessment required to keep ageing equipment in service without risking a catastrophic failure.

SKM's report includes four case studies of distribution networks which demonstrate that maintenance costs rise exponentially with the age of an asset type. These examples include power transformers, cables, zone substation circuit breakers and switchgear.

SKM's report provides compelling additional evidence to demonstrate the robustness of the assumptions underlying the model EnergyAustralia has used to forecast maintenance requirements. The application of the model results in a forecast of maintenance expenditure that is prudent and efficient and therefore reasonably reflects the operating expenditure criteria in the Rules.

In particular, we note that the assumption that maintenance costs rise exponentially with the weighted age of an asset type is supported by theory, practical considerations, and real world examples. We consider that SKM's report can be relied on by the AER because:

- SKM's analysis in 2003 was based on the advice of expert ex-industry engineers with many years of experience in both transmission and distribution operation and maintenance.
- SKM's reasoning for an exponential relationship between age of an asset and maintenance costs is grounded in well established theory and reflects the prudent practices of Australian DNSPs.
- SKM's analysis is far more detailed and transparent than the review undertaken by Wilson Cook. This is discussed below.

Wilson Cook's analysis and evidence cannot be relied on by the AER

Despite the views of engineering experts, Wilson Cook stated that there is "evidence available from New Zealand electricity supply industry suggests that direct costs may not increase exponentially with the average age of the network components." Wilson Cook's use of the word "may" indicates uncertainty about its conclusions. Nor is the evidence it refers to cited.

In the absence of a definite opinion from Wilson Cook, and in the light of the evidence provided by EnergyAustralia, the AER should not use Wilson Cook's advice to reject our forecast of proposed maintenance requirements.

The analysis undertaken by Wilson Cook on New Zealand distributors lacks transparency and detail. A description of their approach is confined to a footnote and clearly is a less robust approach compared to EnergyAustralia's model.

Section 4.6 of SKM's report critically assesses Wilson Cook's analysis of New Zealand utilities. It notes that extreme care needs to be taken when comparing Australian and New Zealand DNSPs. This is because there are significant differences in size between the DNSPs in each country and there are also regulatory and operational differences which impact on the observations of maintenance costs.

SKM also identifies significant flaws in the analysis that could affect the results. In particular, SKM notes that Wilson Cook used two consecutive years of data (2005 and 2006). SKM's view is that the true relationship of operations and maintenance costs versus asset age can only be determined by considering the trend in the costs over the lifetime of an asset.[186] For this reason, SKM states:[187]:

> "…we do not believe that any credibility can be attached to the Wilson Cook observation."

SKM notes that using only two years data means that annual variances, such as the level of storm activity, annual workload scheduling variations with maintenance cycles typically up to 8 years for some assets, and even factors such as growing or reducing maintenance backlogs, can affect the results of the analysis.

SKM also notes that there are only small differences in the average network ages between New Zealand DNSPs. SKM states that trying to determine an opex-age relationship from closely grouped weighted average age of networks gives very low resolution for regression analysis.

EnergyAustralia notes in this respect that the 'cost-age' curves used by EnergyAustralia separate assets into 6 different classes with different cost characteristics. It is unclear whether Wilson Cook undertook such detailed analysis or whether it relied on the regulated asset base (RAB) as a proxy for asset classes. If this is the case, the regression analysis cannot be relied upon due to statistical noise from the different characteristics of assets.

In summary, SKM's advice identifies significant concerns with Wilson Cook's analysis. In light of these concerns, the AER should not accept Wilson Cook's recommendations.

Wilson Cook's substitute estimate of maintenance costs

The AER relied on Wilson Cook's method and values for determining a substitute amount for EnergyAustralia's forecast maintenance requirements. Wilson Cook's substitute amount was based on a 9 per cent forecast increase relative to the normalised base year. Wilson Cook derived this forecast increase by selecting a figure half way between:

- A lower bound of 7 per cent based on Wilson Cook's CSV benchmark analysis of the maintenance costs of NSW and ACT DNSPs
- An upper bound of 11 per cent which represented EnergyAustralia's proposed amount.[188]

Under clause 6.12.1(4) of the Rules, if the AER does not accept the total of the forecast operating expenditure, it must set out its reasons for that decision and provide an estimate that the AER is satisfied reasonably reflects the operating expenditure criteria.

Inconsistent with these Rule requirements, the AER has failed to set out reasons (including findings on material questions of fact and the evidence or other material on which those findings were based) as to why a 9% allowance is an amount that reasonably reflects the operating expenditure criteria. This failure raises the inference that the AER has acted arbitrarily in determining the substitute estimate and has not considered the material provided by EnergyAustralia in support of its proposed estimate. The AER should reconsider the material provided by EnergyAustralia in its June 2008 proposal, together with this submission, and properly make its decision as required under the Rules.

In any event, the outcomes of Wilson Cook's CSV analysis should not be used by the AER to inform conclusions on the efficient level of expenditure on maintenance costs. As set out section 9.2.2 of this revised proposal, the Wilson Cook's CSV benchmark analysis is methodologically unsound and produces anomalous outcomes. Nor is it apparent that Wilson Cook has sufficient expertise to undertake the CSV analysis.

As discussed in section 9.2.2 of this submission, we engaged Huegin to undertake a review of Wilson Cook's CSV analysis.

[186] SKM noted that for the same reasons it did not draw any conclusions from the 3 years of EnergyAustralia data when it developed the model in 2003

[187] SKM, *SKM response to Wilson Cook commentary an O&M/ age profile modelling, Final report,* 5 January 2009, p15.

[188] We note that the 11 per cent is derived after the adjustment for year zero starting point. This is discussed in the next section.

9-11. Operating expenditure
(continued)

In relation to maintenance costs, Huegin noted that a top down analysis must include:[189]

- A thorough understanding of the physical characteristics of the asset and the drivers of maintenance cost including network location and geographical attributes, equipment age and climate.
- Consideration of the maintenance strategy and performance other than cost, for example maintenance effectiveness, maintenance productivity; and maintenance operational purposefulness.

Wilson Cook's CSV analysis of maintenance expenditure does not include consideration of EnergyAustralia's individual circumstances. In this context, EnergyAustralia submitted a report by SAHA on "Electricity distribution business operational expenditure review" at Attachment 6.2 of the June 2008 proposal. SAHA noted that[190]:

> In terms of opex prudence and efficiency, EnergyAustralia achieve similar operating cost outcomes as peer organisations while maintaining higher workloads across most asset classes.

SAHA stated that the main drivers of EnergyAustralia's higher workloads appear to be a combination of a number of factors including:

- older assets with higher failure rates, leading to more maintenance and targeted preventative maintenance programs
- an RCM based maintenance methodology which leads to the extension of assets past their standard lives (where the condition permits), but at a cost of monitoring assets;
- a lower proportion of maintenance repair capitalised, leading to more labour hours recorded against OPEX; and
- the proportion of the network in CBD and Urban areas with limited accessibility – leading to greater labour hours due to larger crew sizes for confined space entry and underground access and longer maintenance times related to difficult-to-reach equipment

In our view, the SAHA report demonstrates that our maintenance forecast is efficient and prudent, and reflects EnergyAustralia individual circumstances. Wilson Cook and the AER, by relying on the CSV analysis, have failed to adequately take EnergyAustralia's circumstances into consideration when assessing whether the forecast meets the operating expenditure criteria, as required by clause 6.5.6(c) of the Rules.

We also note that Huegin conducted alternative benchmark measures of maintenance efficiency to test the veracity of Wilson Cook's CSV analysis. Huegin's findings demonstrate that EnergyAustralia's maintenance expenditure is normal compared to other DNSPs based on two benchmarking tools. Huegin's alternative assessments reviewed the compounding annual growth rate of maintenance costs of DNSPs and also measured maintenance costs as a percentage of the asset base. [191]

Unlike Wilson Cook, Huegin do not rely on its benchmarking analysis to inform findings on the efficiency of maintenance expenditure.[192] In our view, the Huegin material illustrates that benchmarking can yield a number of different outcomes and therefore should not be relied on as the basis of a substitute estimate.

In conclusion, Wilson Cook did not provide sufficient analysis or evidence to demonstrate that the relationship between age and maintenance costs is overstated. The AER should not rely on this opinion, or on the substitute estimate recommended by Wilson Cook.

The AER should place more weight on the information provided by EnergyAustralia in our June 2008 proposal and the additional material in this submission. This information demonstrates the robustness of the exponential age-cost function in EnergyAustralia's maintenance model.

[189] Huegin Consulting, *EnergyAustralia's regulatory proposal review (opex)*, January2009, p76-77
[190] SAHA, *Electricity Distribution Business Operational Expenditure Review*, 4 April 2008, p53.
[191] Huegin Consulting, *EnergyAustralia's regulatory proposal review (opex)*, January2009, Chapter 5
[192] Huegin Consulting, *EnergyAustralia's regulatory proposal review (opex)*, January2009, Chapter 5.

'Year zero' starting point adjustment

The AER adjusted EnergyAustralia's maintenance costs to reflect analysis undertaken by EnergyAustralia during the review process. We note that the AER has characterised this analysis as an amendment to our June 2008 proposal. We note that the information provided on 8 and 15 August 2008 to the AER did not, and cannot, constitute a revised proposal.[193]

The additional analysis undertaken by EnergyAustralia was in relation to an issue raised by Wilson Cook on the starting value for deriving the 'cost-age' asset curves. Wilson Cook considered that EnergyAustralia should use the 2006-07 replacement cost value for the 'year zero' value rather than the value used for the 2004-09 regulatory proposal.

EnergyAustralia's analysis provided to the AER on 8 August 2008 indicates that using the 2006 value results in a $19.4 million ($2008-09) reduction in maintenance costs. EnergyAustralia agrees with Wilson Cook that the 2006 'Year zero' value is better than using the 2002 value for deriving the cost-age curves.

On 15 August 2008, we informed the AER that the predicted average ages of zone and sub-transmission substations in the model were incorrect. The correction resulted in a further $4.1 million reduction in maintenance costs ($2008-09).

EnergyAustralia therefore accepts the AER's finding on the adjustment for these matters and revises its proposal to reflect this finding.

EnergyAustralia has revised its proposal to address the matter raised in the AER's determination concerning the starting year value for deriving the cost curves and the correction of an error in the model. These result in a $23.5 million reduction in the forecast of required operating expenditure.

[193] EnergyAustralia, *Response to Wilson Cook's questions*, 8 August 2008, Question 2.4. Also response to Question 11 of 15 August 2008.

9.4 Workload escalator for AIM and major projects

EnergyAustralia's proposal included adjustments to base year costs to accurately forecast the efficient costs from changes in the volume of work during the period. We documented each of these workload escalators by activity cost and selected the appropriate driver based on the nature of the costs.

We applied a 'real system capex' driver to the base year operating costs of the Asset and Investment Management (AIM) and Network Major Projects and Engineering (Major projects) branches. This recognised that the operating costs of these branches will increase with the real value of the investment program.

The AER accepted the advice of Wilson Cook that the use of real system capex as a driver of workload increase for the asset management and major projects branches is not appropriate.

The AER agreed with Wilson Cook that it is not necessarily the case that large increases in EnergyAustralia's forecast capex will result in similar increases in costs for the supporting asset management and project management branches. It also agreed with Wilson Cook that project value is not necessarily an appropriate measure of the resources required to oversee work. For this reason, the AER accepted Wilson Cook's recommendation that changes in staff in the network division is a more appropriate escalator than increases in real system capex.

EnergyAustralia's comments

EnergyAustralia does not accept the AER's findings. We note that the AER relied on Wilson Cook's analysis without undertaking further examination of the recommendation.

EnergyAustralia provided material in our June 2008 regulatory proposal to describe our efficient forecast processes. On 28 August 2008, we provided specific material in response to Wilson Cook's questions on the selection of the workload driver for the branches.[194] We have re-attached our response at Attachment 9F.

Wilson Cook has not taken this information into account in coming to its conclusions on the appropriate workload escalator. Wilson Cook stated that, if the capital expenditure program is driving these costs, then the costs should be capitalised.

This was despite EnergyAustralia making clear that most of the costs associated with the branches are capitalised.[195] In our response, we noted that the operating costs relate to maintenance planning, reliability analysis and branch management.

We also explained that as the capital program grows, so too will the workload for the branches as projects are developed from the planning to the implementation stage. It is expected that the operating costs will increase in scale with the capitalised costs of the division.

We consider that there is a strong basis for this assumption especially given that the following operating activities will increase in line with the value of the capital program activity:

- governance administration;
- monitoring and reporting on the capital program; and
- updating of maintenance planning based on implementation of the capital replacement program.

The AER should review the material provided in the response of 28 August 2008, particularly as it appears that Wilson Cook has not taken this into account in forming its findings.

Further to this material, we consider our proposed workload escalator is appropriate given the substantial number of new assets being commissioned in the next regulatory period. This is taking place in an increasingly complex network and will involve the meshing of different generations of technology.

[194] EnergyAustralia, *Responses to Wilson Cook's questions of 18th August 2008*, Question 2.

[195] EnergyAustralia noted that only $2.5 million of the total cost of 21.0 million (12 per cent) for the branches was included in operating expenditure in 2006-07.

More maintenance manuals, policies and strategies will be required to ensure best practice operating and maintenance practices.

In this context, the AER should recognise that maintenance policies, planning and analysis result in efficient business decisions. Ultimately, good decisions benefit the customer through investment and operational efficiencies over the long term. In such a way, we consider the expenditure meets the National Electricity Objective of the efficient operation and use of electricity services for the long term interests of consumers of electricity.[196]

Wilson Cook recommended that an escalator based on network division staff should be used as a substitute workload escalator. This is not an appropriate escalator. The forecast capital and operating costs of these branches are directly tied to the capital expenditure program when compared to other operating activity costs.

In addition to this, staff numbers do not capture the increase in total operating costs of the branches and therefore underestimate the future operating costs of the divisions. The network staff numbers do not take into account that EnergyAustralia intends to modestly increase the internal workforce and will rely increasingly on external staff numbers. In this respect, external advice will be important in developing best practice maintenance policies and strategies and this will be a significant portion of the total costs of the divisions.

Based on the reasons above, we consider that the AER should re-assess its finding that real system capex is not an appropriate driver for these tasks.

9.5 Labour cost escalation

EnergyAustralia applied an adjustment to efficient base year costs to take account of the real price of labour over the period. EnergyAustralia did not apply any other adjustments to account for real cost drivers in operating costs.

The AER did not accept the forecast labour costs in EnergyAustralia's forecast of required operating expenditure.

[196] National Electricity Law, Section 7A.

The AER reduced EnergyAustralia's forecast of operating expenditure by $0.4 million. In particular, it raised concerns with EnergyAustralia's proposed method to forecast future movements in labour costs by averaging the forecasts of Econtech and Macromonitor.

The AER substituted EnergyAustralia's proposed labour forecasts with recent labour forecasts from Econtech.

EnergyAustralia's comments

Methodology

EnergyAustralia does not accept the AER's findings on EnergyAustralia's labour cost escalators.

To the extent that cost escalation was a matter addressed in the AER's decision on capital and operating expenditure. EnergyAustralia has set out its detailed comments on labour cost escalators in the revised forecast of section 3.4 of this revised proposal.

In summary, EnergyAustralia noted that:

- The methodology underpinning EnergyAustralia's proposal, proposed by CEG, was to use multiple forecast sources and apply averaging techniques which we consider provides a sound basis on which to forecast future expenditure.
- EnergyAustralia considers that the forecasts produced by Econtech and Macromonitor are equivalent forecasts that can be used for averaging purposes.
- It is not appropriate for a forecast to be dismissed on the basis that it uses an alternate technique to the AER's preferred forecaster.

Updated information

EnergyAustralia has revised its forecast operating expenditure to use updated labour cost forecasts. EnergyAustralia has applied KPMG Econtech's labour cost forecasts consistent with the AER's proposed method.

We are concerned that using a single Econtech forecast exposes EnergyAustralia to too great a risk of a single forecaster's judgement. EnergyAustralia considers that this concern can be mitigated by the AER consulting with businesses as soon as the updated Econtech forecasts become available. This will provide EnergyAustralia and other NSW DNSPs with an opportunity to seek independent review of these forecasts if necessary.

The application of updated forecasts of labour results in a $3 million reduction in forecast operating expenditure.

EnergyAustralia has revised its forecast of required operating expenditure to address the matter raised by the AER on updated labour cost forecasts. This results in a $3 million reduction in forecast operating expenditure from the June 2008 proposal.

9.6 Self insurance costs

The AER reduced EnergyAustralia's proposed self insurance costs from $30 million to $21 million. It considered that all the proposed self insurance premiums reflected the efficient costs that a prudent operator in the circumstances of the DNSP would require to achieve the operating expenditure objectives and that in several areas they did not represent a realistic expectation of the costs of self insurance in the next period. As a result, AER excluded the following self-insurance events:

- Bomb threat/ hoax, terrorism
- Bushfire
- Risk of non-terrorist impact of planes and helicopters
- Poles and lines
- Key assets
- Key person risk
- General public liability risk
- Guaranteed service level (GSL) payments

EnergyAustralia's comments

EnergyAustralia does not accept the AER's findings to exclude certain self insurance events The AER did not provide sufficient evidence to suggest that the assumptions underlying the SAHA model are incorrect or that the AER's substitute amount accords with the Rule requirements.

9–11. Operating expenditure
(continued)

Assumptions and methodologies are sound

EnergyAustralia notes that its proposals are based on the advice of SAHA. Two actuaries undertook detailed reviews of SAHA's quantifications including the assumptions and methodologies in the report. We consider that the AER is not in a position to make informed decisions on such matters without the assistance of experts.

EnergyAustralia engaged SAHA to provide its view on the AER's decision. SAHA's full report is at Attachment 9G. It considered:

- Actuarial practitioners would not have formed the same opinion as the AER.
- The AER was incorrect in rejecting certain events due to an imperfect data set or because the risk had never affected the DNSP.
- Competitive businesses would not adopt the same approach to mitigating risks as that advocated by the AER.

SAHA reiterated that its assumptions reflect independent, unbiased estimates of the probability and consequence of each risk. SAHA also provided additional evidence to demonstrate the robustness of the assumptions and methodologies.

EnergyAustralia considers that the AER should reconsider its findings in light of the attached SAHA report.

The AER has not taken into account the NEL revenue and pricing principles

EnergyAustralia notes that the AER must give reasons for substitute estimates of operating expenditure if is not satisfied that the expenditure meets the operating expenditure criteria in the Rules and that any such substitution must be done in accordance with clause 6.12.3(f) of the Transitional Rules. In the case of self insurance, the AER did not give clear reasons for estimating a value of zero for certain self insurance events or provide any details supporting the basis for a zero substitution for amounts proposed by EnergyAustralia.

That is, the AER removed the self insurance risk because it did not agree with the methodology or assumption provided by SAHA. This is entirely different from suggesting that there is no likelihood of the risk occurring. In these cases, the AER must give reasons for considering why the risk does not exist.

In addition to this, there is no evidence that the AER has appropriately taken into account the NEL revenue and pricing principles. The AER has rejected EnergyAustralia's definition of guaranteed service level payments without reference to section 7A(2)(b) of the NEL requirement that EnergyAustralia be provided with a reasonable opportunity to recover at least the efficient costs incurred in complying with a regulatory obligation or requirement of making a regulatory payment. A regulatory payment is defined in section 2E of the NEL to include a sum that a DNSP has been required to pay for a breach of a distribution reliability standard or a distribution service standard because it was efficient for the DNSP to pay that sum.

9.7 Debt raising costs

In its June 2008 proposal, EnergyAustralia proposed that:

- The unit cost of debt raising should be set at least equal to 15.5 bbpa of the amount of debt to be raised.
- The cost of debt raising should include both the direct (i.e. underwriting) and indirect (i.e. underpricing) costs. The 15.5 bbpa therefore comprises of 12.5 bbpa for direct and 3 bbpa for indirect debt raising cost.

This proposal was based on advice from the Competition Economists Group (CEG) set out in attachment 8.2 to our June 2008 proposal and on this basis; EnergyAustralia calculated an amount of $50 million ($2008-09) as debt raising costs to be included in its original total forecast operating expenditure for the 2009-14 regulatory period.

In its draft determination, the AER rejected the relevance of the study that considered the cost of debt issues in the United States over the period 1970 to 2000. This study was cited by CEG to support the direct debt raising unit cost of 12.5 bbpa. To this amount, an estimate of 3 bbpa for indirect debt raising cost was added to arrive at a total of 15.5 bbpa.

The AER considered that:

- the average direct debt raising cost of the average US public debt issue is not representative of the cost of raising debt by a regulated business in Australia; and
- using the mean estimate of firms across an economy to estimate the direct cost of debt raising for a regulated firm is

not reasonable, given that a regulated firm should have the lowest cost of debt raising due to their stable, regulated cash flows.

The AER also rejected the inclusion of indirect debt raising cost. The AER argued that by underpricing, a regulated firm is effectively issuing a higher yielding lower grade debt (i.e. a debt with a grading lower than BBB+). The AER concluded that underpricing would be is inconsistent with the benchmark debt grade of BBB+ assumed in the Rules.

Accordingly, the AER was not satisfied that:

- the current method that it uses to calculate direct debt raising cost is under compensating regulated firms; and
- there is a need to provide for indirect debt raising cost. The AER considers that indirect debt raising costs do not reflect the efficient cost that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the operating expenditure objectives.

The AER allowed for the direct cost of debt raising only and calculated this cost using the method that it has applied in previous revenue determinations. This resulted in an allowance for EnergyAustralia of 8 bbpa and $26 million ($2008-09) for the 2009-14 regulatory period.

EnergyAustralia's comments

EnergyAustralia does not accept the AER's decisions:

- To reject the relevance of the evidence cited in our June 2008 proposal to support the setting of direct debt raising unit cost of at least 12.5 bbpa.
- To reject the inclusion of indirect debt raising cost.

We note that subsequent to the submission of our June 208 proposal, the Energy Network Association (of which EnergyAustralia is a member), together with Grid Australia and the Australian Pipeline Industry Association (Joint Industry Association) provided to the AER on 11 November 2008 a submission on the cost of debt and equity raising. This submission reinforces our June 2008 proposal. The Joint Industry Association's submission can be found at attachment 3N (The JIA submission).[197]

EnergyAustralia's response to the matters raised by the AER in its draft determination is supported by analysis contained in a report prepared by CEG who was engaged by EnergyAustralia, together with other NSW and Tasmanian businesses. This report is at attachment 3O. (The CEG report)[198]

Additionally, we have also commissioned another independent appraisal of the AER's decisions with respect to the cost of raising debt and equity. This report provides counter arguments to the AER's reasons for excluding the indirect cost of debt raising. This appraisal can be found at attachment 3P. (The Carlton report)[199]

No reason to exclude US data

In its draft determination, the AER consider that the use of private placement underwriting costs are a reasonable proxy for public issuance underwriting costs as these are not observable in the Australian market.

EnergyAustralia considers that relying on the cost of issuing private debts as a proxy for the costs of public debt issue is not reasonable, particularly when there is data available that may be used for estimating the cost of a public debt issue. This data is supplied in a study by Saunders Palia and Kim cited in the CEG report which was attached to our original proposal. The AER rejected the data from this study because this data is for the United States and does not contain regulated utilities in the sample used.

EnergyAustralia does not accept these reasons of the AER. Firstly, the fact that this data is for the US is not in itself a reason for rejecting its relevance. It is more than likely that the cost of raising debt in the US is lower than the cost of raising debt in Australia because of the depth of the US financial

[197] Joint Industry Submission, *Submission on debt and equity raising costs*, 11 November 2008.

[198] CEG, *Debt and equity raising costs – A response to the AER 2008 draft decisions for electricity distribution and transmission*, January 2009, paragraph 142

[199] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia,* January 2009

market. This is consistent with recent paper by Bortolotti, Megginson and Smart (cited in the Carlton report) which found that the US has the lowest cost of raising equity in the world.[200]

Secondly, the sample used by the AER to estimate the cost of issuing private debts in the US also does not contain regulated utilities; the same reason used by the AER to reject the data of Saunders Palia and Kim.[201]

The AER's assertion is inconsistent with the Rules requirements

The AER argued that a regulated firm should have among the lowest cost of debt raising due to stable, regulated cash flows.

However, such an assertion is inconsistent with the benchmark assumptions of 60% debt gearing and BBB+ credit rating contained in the Rules.

The Rules stipulate that the cost of capital should be estimated based on a gearing benchmark of 60%. Accordingly, for this level of gearing, the Rules set a Standard and Poors credit rating of BBB+.

A BBB+ credit rating is at the lowest end of investment grade credit rating[202]; effectively meaning that investors are not certain that their loans will be repaid in full.

Gearing level and credit rating impact on the cost of debt raising. Saunders Palia and Kim found that the cost of debt raising rises with increases in the gearing level.[203]

[200] The result of this study can be found in table 5 of Attachment 3P: Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia*.

[201] CEG, *Debt and equity raising costs – A response to the AER 2008 draft decisions for electricity distribution and transmission*, paragraph 138

[202] This is common market terminology. As noted in Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia*, debt rating of BB, B and CC are regarded as having significant speculative characteristics (i.e. riskier).

[203] This study is referred to in CEG report, *Debt and equity raising costs – A response to the AER 2008 draft decisions for electricity distribution and transmission*, attachment 3O (paragraph 146).

Therefore it is inconsistent with the Rules requirement for the AER to argue that a regulated firm, with a gearing ratio of 60% and a BBB+ credit rating, would have among the lowest cost of debt raising; given that a gearing level of 60% is higher than the average gearing level of other businesses in the economy.

Underpricing is not solely a function of credit rating

The AER rejected the inclusion of indirect debt raising cost in the calculation of an allowance for debt raising cost. This rejection is on the basis that underpricing effectively results in a debt with a rating lower than the benchmark BBB+ assumed in the Rules.

EnergyAustralia contends that this assertion by the AER is not correct. Issuing a debt at a discount (i.e. underpricing) is to ensure the success of raising capital. Discounting a debt is to compete for liquidity and is done by many firms within each rating category.

The Carlton report also points to a study of underpricing in the US market which demonstrates that pricing of debt is not simply a function of credit rating.[204]

Indirect cost meets the operating expenditure objectives.

The Carlton report canvassed the views of market practitioners which indicated that discounting would be required for a large scale issue of a BBB+ debt. This is essentially because the Australian debt market is relatively illiquid, especially compared to the US market.

The Carlton report also concluded that due to the relative illiquidity of the Australian market compared to the US market, any estimates of the underpricing based on US data would be lower than that of Australia. This is consistent with the proposition stated above that any cost of debt raising in the US would be lower than the cost of debt raising in Australia due to the depth of the US market.

[204] Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia*", page 32.

The illiquidity of the Australian debt market would also mean that in a typical debt raising exercise, access to international debt market would be necessary. It would follow that data in debt markets other than Australia (e.g. US debt market) would be relevant for estimating the cost of debt raising for an Australian firm; not the opposite as the AER has argued.

Additionally, that the JIA submission also noted that:

- The efficient cost of debt raising is not restricted to the direct cost but also includes indirect costs associated with underpricing.
- Basic economic theory and empirical evidence show that direct and indirect cost of debt raising are identical economic costs and are often used in conjunction to achieve optimal cost outcomes (that is, to minimise the total cost of raising capital).
- The decision by the regulators in the past to provide compensation for direct cost only and to ignore indirect cost is inconsistent with both finance literature and sound economic principles.

The indirect cost of raising debt is an important element of an efficient capital raising strategy. It, therefore, meets the operating expenditure criteria and is an efficient cost that a prudent operator in the circumstances of the NSW DNSPs would incur.

Accordingly, EnergyAustralia submits that the AER should reconsider its decision to reject the inclusion of indirect debt raising cost.

In this revised proposal, EnergyAustralia has maintained its original proposal that:

- the cost of debt raising should be set to include both direct and indirect costs; and
- this amount should be based on 15.5 bbpa reflecting 12.5 bbpa for direct costs and 3 bbpa for indirect costs.

9.8 Equity raising costs

The AER reduced EnergyAustralia's proposed equity raising cost from $49 million to $36 million. Similar to the issue of indirect debt raising costs, the AER rejected EnergyAustralia's proposal to include indirect costs in the benchmark equity raising costs. The AER also made some adjustments to the cash flow approach to determining the benchmark equity raising costs.

The AER also noted its preference to treat equity raising costs as capital expenditure and therefore did not include equity raising costs in its substitute estimate forecast of operating expenditure requirements.

EnergyAustralia's comments

EnergyAustralia wishes to make clear that we do not accept the AER's decision to reject our proposed forecast of equity raising costs.

However we do accept the AER's preference that equity raising costs should be capitalised rather than included in the forecast of operating expenditure. EnergyAustralia has consequently revised its forecast of operating expenditure to remove equity raising costs. It has subsequently revised the forecast of capital operating expenditure to include equity raising costs.

EnergyAustralia has revised its forecast operating expenditure to remove equity raising costs and transfer these costs to forecast capital expenditure. This results in $49 million reduction in forecast operating expenditure.

9.9 Consequential revisions to forecast operating expenditure

EnergyAustralia has revised its forecast of required operating expenditure to ensure consistency with other revisions in the revised proposal.

Specifically, the revised capital expenditure impacts on maintenance operating requirements. EnergyAustralia has used its maintenance model to determine the revised forecast maintenance requirements. This results in a $4 million reduction to forecast operating expenditure compared to the June 2008 proposal.

The revised capital expenditure forecast in addition to the revised opening regulatory asset base impact on debt raising costs. The revised debt raising costs has been calculated using the method in the post tax revenue model and results in a $1 million increase in the forecast of operating expenditure compared to the June 2008 proposal.

The revised peak demand forecasts impacts on demand management operating expenditure. The revised forecast expenditure on demand management has been calculated using the same methodology as the June 2008 proposal and results in a $1 million reduction in the forecast of operating expenditure compared to the June 2008 proposal.[205]

On a final matter, the Energy Industries Super Board has advised us that our annual contribution to the superannuation fund used to meet our superannuation obligations arising from the defined benefits scheme is likely to be increased as a result of poor stock market performance over the last year. This is a cost that is unavoidable and must be contributed in order to ensure employee entitlements are protected. EnergyAustralia has not been advised of the amount of the contribution required, but expects formal advice in February. EnergyAustralia therefore intends to provide an updated assessment of its superannuation costs to the AER to allow it to take account of these costs in its final determination.

EnergyAustralia has revised its forecast operating expenditure to be consistent with revisions to other elements of this revised proposal. This results in $3.9 million reduction in the forecast operating expenditure.

9.10 Summary of revised forecast operating expenditure

EnergyAustralia has revised its forecast of operating expenditure to account for:

- "year zero" starting point data used in EnergyAustralia maintenance model
- more recent forecast of labour cost escalators
- transferring equity raising costs from operating to capital expenditure.
- consequential revisions to reflect other revisions in the proposal.

The impacts of these changes are summarised in Table 9.1.

[205] Attachment 5.3 to the regulatory proposal, *Revised DM Impact on 2009-14 Capital Forecast*

Table 9.1 EnergyAustralia's revised forecast operating expenditure 2009-2014 ($2008-09 million real)

	2010-14	FY10	FY11	FY12	FY13	FY14
June 2008 proposal[206]	3071	565	583	618	643	660
Year zero data and errors	-23.6	-2.0	-3.2	-5.0	-5.1	-8.3
Labour escalation	-3.0	-1.0	1.9	2.4	-1.9	-4.5
Equity raising	-48.5			-16.2	-16.2	-16.2
Other revisions[207]	-3.9	0.1	0.1	-0.6	-1.8	-1.9
Revised proposal[208]	**2991**	**563**	**582**	**599**	**618**	**630**

[206] This includes the debt and equity raising costs proposed in the June 2008 proposal.

[207] This includes revisions to maintenance costs, project based demand management costs and debt raising costs based on other revisions in this proposal.

[208] This includes revised debt raising costs. Numbers may not add due to rounding.

12. Corporate income tax

REVISED PROPOSAL

EnergyAustralia has revised its corporate income tax for each regulatory year of the 2009-14 regulatory period.

In its draft decision, the AER noted that, in establishing the opening tax asset base as at 1 July 2009, "each of the businesses presented data that aligns with their 2007 tax assessments and forecast the movements between 2007 and 2009 on the basis of forecast capex, disposals and tax depreciation".[209] This raises the issue of the use of estimates of net capital expenditure.

The revision to EnergyAustralia's corporate income tax is to respond to a matter raised by the AER. This revision is to replace the estimate of net capital expenditure[210] for the 2008 FY with actual value which was not available at the time of submitting the June 2008 proposal.

Corporate income tax allowances are outputs from the post tax revenue model (PTRM) which calculates the tax allowances in accordance with clause 6.5.3. Consequently, revisions to the inputs into the PTRM would result in revision to the corporate income tax.

EnergyAustralia's revised corporate income tax therefore incorporates all those revisions made in this response that have a consequential impact on the calculation of the corporate income tax, e.g., revised forecast capital expenditure.

EnergyAustralia has made no changes to either its approach to establishing the opening tax value of the RAB as at 1 July 2009 or the standard and remaining tax lives. This approach and the standard and remaining tax lives were considered by the AER in its draft decision as appropriate and reasonable.

This chapter has been substituted for Chapter 12 of Part 1 of the June 2008 proposal, except for Attachment 12.1 which contains the methodological approach adopted by EnergyAustralia for setting the opening tax base. This chapter and Attachment 12.1 to the June 2008 proposal now comprise EnergyAustralia's current proposal in relation to Corporate Income Tax for each year of the regulatory control period.

Rule requirements

The AER's distribution determination is predicated on a decision on the estimated cost of corporate income tax to the provider for each year of the regulatory control period in accordance with clause 6.5.3. (Clause 6.12.1(7))

Our June 2008 building block proposal

Based on the PTRM submitted as part of the June 2008 proposal, an allowance for corporate income tax for each regulatory year of the 2009-14 regulatory period was calculated. These allowances totalled $419 million ($ nominal).[211]

AER's draft determination

The AER has decided a corporate income tax allowance to EnergyAustralia for each regulatory year totalling $387 million for the next regulatory period. These allowances were calculated based on the inputs into the PTRM that had been assessed by the AER.

The AER considered that EnergyAustralia's standard and remaining tax lives, approach to establishing the opening tax RAB and the allocation of this RAB value between Transmission and Distribution to be appropriate and reasonable.

Our response to the AER's draft determination

In this revised proposal, EnergyAustralia concurred with the AER's findings with respect to:

- the standard and remaining lives;
- the approach to establishing the opening tax RAB and

[209] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p208.
[210] Net capital expenditure is capital expenditure less disposals.

[211] Table 12.1 of the June 2008 Proposal

- the approach to allocating the opening tax RAB between Transmission and Distribution.

Based on EnergyAustralia's PTRM, the allowance of corporate income tax to EnergyAustralia for each regulatory year of the 2009-14 regulatory period are set out in table 12.3 of section 12.2.

12.1 EnergyAustralia's revised Opening tax RAB and tax depreciation

The substitution of 2008 FY actual net capital expenditure for estimates used in the June 2008 proposal resulted in revised:

- value of opening tax RAB as at 1 July 2009.
- value of tax depreciation of the opening RAB for the 2004-09 regulatory period.

The revised value is $4,997 million and is classified as $4,361million for distribution (other than dual function) assets and $636 million for transmission (dual function) assets. Table 12.1 reconciles the opening tax value as per the June 2008 proposal to the revised value.

The revised total tax depreciation for the 2009-14 regulatory control period is $940 million. Table 12.2 shows the revised total tax depreciation on opening RAB; classified into portions for transmission (dual function) assets and for other distribution assets.

Table 12.1 Revised opening tax RAB value @ 1 July 2009

$ million (nominal)	Total	Distribution	Transmission
Opening tax RAB as per original proposal	4,961.5	4,378.8	582.7
Add/(less) additional/(reduced) capital expenditure	34.5	(16.0)	50.5
Add: reduction in tax depreciation	1.4	0.9	0.5
Add/(less): increase/(reduction) in non system reallocation	0	(2.0)	2.0
Revised opening tax RAB	4,997.4	4,361.7	635.7

Table 12.2 Revised tax depreciation on opening tax RAB - Total

$ million (nominal)	FY10	FY11	FY12	FY13	FY14
Total	317.9	185.1	164.8	143.7	128.2
Other distribution	285.9	168.5	150.5	131.6	116.9
Transmission (dual function)	32.0	16.6	14.3	12.1	11.3

12.2 EnergyAustralia's revised corporate income tax

The revised opening tax RAB and tax depreciation values are inputs into the PTRM which, incorporating other revised inputs, calculates the allowance for corporate cost of income tax in accordance with clause 6.5.3. The revised allowance for corporate income tax to EnergyAustralia for each year of the next regulatory period is shown in the table below.

12. Corporate income tax (continued)

Table 12.3 Revised allowance for corporate income tax

$ million (nominal)	FY10	FY11	FY12	FY13	FY14
Income tax liability	87	90	178	203	215
Less: value of imputation credits	44	45	89	102	108
Estimated cost of corporate income tax	43	45	89	101	107

13. Revenue or price limits (X-factors)

REVISED PROPOSAL

EnergyAustralia has revised its proposal in relation to X-factors for standard control services. This is to:

- Apply revised energy forecasts that take account of electricity price impacts (driven by the Carbon Pollution Reduction Scheme (CPRS), various NSW government levies and the AER's Network determination for the period 2008/09 to 2013/14) and an updated outlook for economic growth; and
- To incorporate changes to the X-factors that are a consequence of the revised Annual Revenue Requirement (as set out in chapter 1).

This chapter (including Attachment 13A) together with Chapter 13 (including Attachment 13.2) of the June 2008 proposal now comprises EnergyAustralia's current proposal in relation to X-Factors. The tables in Chapter 13 of the June 2008 proposal are now overtaken by the tables in this Chapter. Whilst the actual forecast contained in Attachment 13.2 to the June 2008 proposal has now been revised as set out in Attachment 13A. The forecasting methodology set out in Attachment 13.2 has been applied to the revised forecast and is therefore still relevant and part of the current proposal.

Rule requirements

The AER's distribution determination is predicated on a decision on the control mechanism (including the X-factor) for standard control services (Clause 6.12.1 (ii)),

The X-factors must be set with regard to the distribution business's total revenue requirement.)

Our June 2008 building block proposal

The X-factors proposed by EnergyAustralia in its 2 June 2008 proposal for transmission services and distribution standard control services are set out in Table 13.1.

AER's draft determination

The AER determined X-factors for both the distribution and transmission networks which were different to those proposed by EnergyAustralia. In changing the X-factors, the AER changed the X-factor for the first year of the regulatory control period only.

The AER agreed with its consultants, McLennan Magasanik and Associates (MMA), that EnergyAustralia's method of forecasting energy volume and customer numbers provides a realistic expectation of the demand forecast to achieve particular capital expenditure and operating expenditure objectives[212], However, it also requested that the forecasts should be updated to take into account more recent data.

Our response to the AER's draft determination

Since the preparation of the June 2008 volume forecasts, important developments with respect to a number of the key drivers of energy volume growth have emerged.

EnergyAustralia has revised its volume forecasts to account for new data, and this is consistent with the AER's request that EnergyAustralia review its energy forecast to incorporate up to date data. In complying with the AER's request, EnergyAustralia has revised its energy and peak demand forecasts for a wider number of factors than listed in the AER's request. This is to ensure that relevant data which has become available since June 2008 has been incorporated into the forecasts.

EnergyAustralia has revised its proposal in relation to X-factors for the reasons set out in the following sections:

- EnergyAustralia does not accept the AER's decision on X-factors for the reasons set out in section 13.1.
- EnergyAustralia accepts the AER decision in relation to customer number forecasts and agrees that it is appropriate to update its customer numbers to take account of actual customer numbers in 2007/08.
- EnergyAustralia agrees that it is appropriate to update its energy forecasts. However, EnergyAustralia does not agree with the methodology stipulated by the AER to update the

[212] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p116

13. Revenue or price limits (X-factors) (continued)

forecasts. EnergyAustralia considers that a further review of energy and peak demand forecasts is appropriate to take account of factors that will impact on energy sales, including recent government policy initiatives that will impact on energy prices, and the emerging more pessimistic outlook for economic growth. Accordingly EnergyAustralia has revised its energy and peak demand forecasts as set out in Section 13.2

- EnergyAustralia has revised its X-factors to take account of other factors as outlined in section 13.3.

13.1 X-factor

The AER's draft decision on X-factors for distribution and transmission is based on its analysis of other elements of our proposal set out in its decision. The AER's PTRM calculates X-factors with the following inputs:

- 2008-09 tariffs;
- a discount rate;
- the annual revenue requirement; and
- the energy volume & customer numbers forecast.

These inputs are directly related to the AER's decisions on Rate of Return, Annual Revenue Requirement & other amounts, values and inputs, including the volume forecasts. The X-factors are also indirectly affected by other AER decisions, such as the allowed capital expenditure and operating expenditure, which are themselves components of the AER's decision on the Annual Revenue Requirement.

The X-factors proposed by EnergyAustralia in its June 2008 proposal are set out in Table 13.1.

Table 13.1 June 2008 proposal X-factors (%)

	FY10	FY11	FY12	FY13	FY14
Distribution price	-29.41	-10.43	-10.43	-10.43	-10.43
Transmission revenue	-8.42	-15.77	-15.77	-15.77	-15.77

The AER accepted EnergyAustralia's proposed X-factors for the last four years of the regulatory period, in order to manage stakeholder concerns about the initial year (2009-10) price change. This approach allowed the AER to minimise the X-factor in the first year, thus reducing the initial price impact to consumers. In applying this method the AER ensured that the present value of the annual revenue required for EnergyAustralia's expenditure profile was the same as the expected annual revenue to be recovered from customers.

The AER's method increased the variance of expected revenues in the final year of the control period.

While the resulting difference between the annual revenue requirement and expected revenues in the final year has increased from what EnergyAustralia proposed in June 2008, the AER considers the expected variance in revenue has been minimised as far as is practical in the context of stakeholder concerns.[213]

The X-factors calculated by the AER are set out in Table 13.2.

Table 13.2 AER draft determination X-factors (%)

	FY10	FY11	FY12	FY13	FY14
Distribution price	-24.30	-10.43	-10.43	-10.43	-10.43
Transmission revenue	-3.26	-15.85	-15. 85	-15. 85	-15. 85

EnergyAustralia's comments

EnergyAustralia does not agree with the X-factors in the AER's draft determination because we have not accepted the AER's decisions on other key elements of the building block proposal, which have a consequential impact on the calculation of X-factors. These consequential impacts arise from the way that the AER's PTRM applies X-factors using the inputs listed above.

EnergyAustralia is concerned that the AER's approach has led to an increase in the variance in revenues in the final year and therefore may be inconsistent with the Rule requirement to minimise the variance between the following:

- annual revenue required for EnergyAustralia's expenditure profile in 2013-14; and
- expected revenue in 2013-14.

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[213] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p307

EnergyAustralia's proposed method was to set X-factors to minimise the variance between the expected revenue and the annual revenue requirement for the first year (2009-10) and recover the present values of the required revenue for the following four years using a constant annual X-factor. This method was consistent with the AER's past practice applied in transmission revenue determinations.

The AER appears to have changed its preference and adopted a method that applies EnergyAustralia's constant X-factors for years 2-5, but minimises the X-factor in the first year, at the expense of ensuring that revenues earned in the first year using the X-factor equal the annual revenue requirement for year 1. EnergyAustralia is concerned that the AER's new method is driven by stakeholder concerns at the expense of moving away from the intent of the Rules which is to minimise variance in revenues in the final year.

EnergyAustralia considers that it is important that revenues be recouped early in the period when energy forecasts are more reliable. This is the case in general, but is particularly relevant in the context of the CPRS and changing economic environment (i.e potential for recession). EnergyAustralia's annual pricing method which applies a WAPC is highly dependent on accurate energy forecasts, and if actual energy sales are below that forecast in the proposal, there is a risk that allowed revenues will not be recouped in that year. Further, the side constraints that apply to the WAPC formula will constrain EnergyAustralia's ability to recoup any revenue shortfall in future years. It should be noted that there is a risk that revenues could increase if actual energy sales are higher than the forecast.

EnergyAustralia also notes that the revenue certainty faced by distribution businesses is lower than the stability of revenues earned by transmission businesses due to the volatility of energy volumes under a WAPC compared to the stability of a revenue cap and its accompanying unders and overs mechanism. The framework does not take account of this additional risk borne by distribution businesses and typically applies the same WACC to both types of business. The AER should consider the revenue risk faced by distributors as a factor in favour of allowing distributors to earn revenues earlier in the period rather than later in the period (even when the two options are NPV neutral). This will go some of the way to addressing the revenue uncertainty faced by distribution businesses, particularly in the current economic and political environment where the outlook for energy consumption is relatively more uncertain.

In light of the need to recover revenues early in the period, and in light of the Rule requirements to minimise the variance between expected and required revenues in the final year of the period, EnergyAustralia considers that the AER should review its method of calculating X-factors. However, we note that the risk has been addressed through the application of the G-factor in the control mechanism and revision to the demand forecast. If the G-factor is not accepted by the AER, it must re-consider its method used to calculate X-factors and allow EA to recover revenues as early as possible (ie: change its method to minimise variation in the last year.

In this revised proposal, for the sake of comparing the impact of EnergyAustralia's revised proposal with the AER's draft determination, EnergyAustralia has applied the same method used by the AER to calculate X-factors for the revised proposal.

Using the AER's method, EnergyAustralia has calculated the X-factors shown in Table 13.3

Table 13.3 Revised proposal X factors (%)

	FY10	FY11	FY12	FY13	FY14
Distribution price	-39.29	-14.29	-14.29	-14.29	-14.29
Transmission revenue	-17.08	-15.43	-15.43	-15.43	-15.43

13.2 Revised energy forecasts

The AER rejected EnergyAustralia's energy and customer number forecasts because, it considered, the forecasts were outdated and therefore were inappropriate inputs for the AER's PTRM. Instead, the AER's draft determination relied upon the following information which it requested on 8 October 2008:

- a revised customer number forecast, using actual 30 June 2008 customer numbers as a starting point;
- a revised energy consumption forecast, using unaudited 2007-08 WAPC energy data as a starting point; and
- the forecasts should be based on a more recent economic outlook projection from a reputable forecaster.

13. Revenue or price limits (X-factors) (continued)

On 29 October 2008, EnergyAustralia provided this updated forecast to the AER. The AER considered EnergyAustralia's forecasting method to be reasonable, and those updated forecasts formed the volume basis for the X-factors set out in the draft determination. The AER considered the revised customer number forecast provided by EnergyAustralia on 29 October 2008 to be an appropriate input into the PTRM, and accepted it under clause 6.12.1(10) (other appropriate amounts values or inputs) of the transitional chapter 6 rules.

However, the AER's draft determination contains an instruction that, by 20 February 2009, EnergyAustralia is to provide a further revised forecast which is to:

> .. use the audited energy data for 2007-08 as a starting point, which should then be grown at the rate applied within the original energy forecast in EnergyAustralia's regulatory proposal. The new data is to be weather corrected and allocated according to the methodology applied in generating the original energy forecast. The new energy forecast should incorporate the revised customer number forecast provided to the AER on 29 October 2008.

EnergyAustralia comments

EnergyAustralia considers that the AER's directions on how the energy forecast should be revised to be inappropriate, and will result in an unreasonable volume forecast.

The AER's draft determination rejected EnergyAustralia's forecast on the basis that it incorporated outdated data. The AER has applied a principle of using the most up to date information available as inputs into the PTRM, and this principle is applied widely by AER. It has stated that it intends to update capital and operating expenditures for actual 2007-08 expenditure, actual CPI, and new forecasts for both labour and material escalators prior to making its final determination. EnergyAustralia considers that updating for information that has become available since the June 2008 proposal was submitted is reasonable.

EnergyAustralia has reviewed its energy forecast in light of the AER's principle to use updated information, and has explicitly considered the impact of new economic circumstances and government policy initiatives on energy use during the forecast period. As a result of this review, EnergyAustralia has revised its energy and peak demand forecast. Attachment 13A - *Revised Energy and Global Peak Demand Forecasts to 2014* sets out details of the revised forecasts. The revised forecasts have been independently reviewed for reasonableness by Oakley Greenwood Pty Ltd, and that review, entitled *Review of Revised forecasts for EnergyAustralia* is provided as Attachment 13B of this revised proposal.

The remainder of this section sets out the revised energy forecasts and the consequential impact on X-factors. EnergyAustralia's revised peak demand forecast and its implication for capital expenditure has been discussed separately in section 3.

Revised forecast requested by AER

As noted above, the AER's draft determination contains an instruction that, by 20 February 2009, EnergyAustralia is to provide a further revised forecast which is to:

> ... use the audited energy data for 2007-08 as a starting point, which should then be grown at the rate applied within the original energy forecast in EnergyAustralia's regulatory proposal. The new data is to be weather corrected and allocated according to the methodology applied in generating the original energy forecast. The new energy forecast should incorporate the revised customer number forecast provided to the AER on 29 October 2008.

Energy Australia believes that implementation of the above request would result in an unrealistic forecast for the following reasons:

- The application of the "original" growth rates to weather corrected base year (2007-08) data would inappropriately double count the impact of the relatively mild weather experienced in 2007/08;
- The incorporation of the revised customer numbers presents an inconsistency with the original growth rates, as the original growth rates were to an extent driven by the original customer number forecasts; and
- The "original" growth rates were to a large extent driven by economic growth projections which MMA has considered to be outdated. The AER's reason for rejecting the June 2008 volume forecasts was that they were based on outdated assumptions, yet the AER's instruction to rely on the "original" growth rates in effect compels EnergyAustralia to use those same outdated assumptions.

Consequently, to provide a "reasonable" expectation of energy and peak demand growth, EnergyAustralia considers it is necessary to use current data and thoroughly revise its forecasts using the process which AER has endorsed as reasonable. At the same time, in revising its forecasts, EnergyAustralia has adopted those process improvements and suggestions from MMA which EnergyAustralia considers appropriate.

Other drivers of revised energy forecast

EnergyAustralia's original energy forecast explicitly and clearly excluded the impact on volumes associated with possible electricity price changes. This was primarily because at the time there was a high level of uncertainty as to the impact of climate change policies and the AER's Network determination on retail prices. However, in more recent months several government policy initiatives have been announced and the world has entered a severe economic downturn that has changed the forecast of Australia's economic growth in the short and medium terms.

EnergyAustralia has considered the impact of the following factors in its revised energy and peak demand forecast:

- the introduction of the CPRS (Carbon Pollution Reduction Scheme);
- updated economic growth forecasts;
- draft outcomes of network price increases (taken from AER's draft determination);
- outcomes of IPART's retail price determination; and
- NSW government initiatives relating to coal royalties & distribution levies.

EnergyAustralia has considered each of these issues in turn and described the impact each factor has on its revised energy and peak demand forecast in the sections below.

MMA's review of the energy forecast

Prior to June 2008, EnergyAustralia was of the view that it could not reliably forecast the impact of the proposed CPRS on energy volumes.

MMA, in its report for the AER released in September 2008 noted the likelihood of higher prices for wholesale electricity as a result of the introduction of a carbon trading scheme and the likely price effect of network determinations. MMA went so far as to put forward two forecasts, one including the potential impact of future price changes on volume growth in the residential sector, and one excluding this impact.

MMA considered the impact on volumes of price trends set out in TransGrid's 2008 Annual Planning Report. The assumed trend was that real electricity prices would increase by 25% between 2007 and 2014, including an increase of 15% between 2009 and 2014. MMA's report indicates that MMA expect that such a price increase would induce a reduction in energy consumption in the residential sector of approximately 4% by 2013-14. It is noted that MMA did not conduct similar price sensitivity analysis for the non-residential sector or for global peak demand.

EnergyAustralia has reviewed MMA's findings in relation to the price elasticity of demand and used this to inform its revised energy and peak demand forecast.

Carbon Pollution Reduction Scheme (CPRS)

Since EnergyAustralia submitted its regulatory proposal in June 2008, three significant reports have been published in relation to the CPRS.

First, in July 2008, the Department of Climate Change released its green paper on the CPRS, which estimated that a $20 carbon price would result in a 16% electricity price increase for households in 2010-11.[214]

Secondly, in October 2008, the Commonwealth Treasury received a report by MMA that forecast a CPRS-related electricity price impact of up to 28% over the 2010-2020 period.[215]

Thirdly, in December 2008, the Department of Climate Change released its white paper on the CPRS, which estimated that a $25 carbon price would result in the electricity price increasing by 18% for households.[216] This is assumed to be an increase in

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[214] Department of Climate Change, *Carbon Pollution Reduction Scheme Green paper*, July 2008, p282

[215] MMA report "*Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Markets*", 11 December 2008

[216] Department of Climate Change, *Carbon Pollution Reduction Scheme White Paper*, Executive summary, page xli

2010-11, which would be consistent with the analysis in the green paper.

The CPRS in intended to change the consumption patterns of consumers and business. Economics tells us that as the price of electricity rises, it is likely that at least a portion of businesses will look for more cost effective production processes and at least a portion of households will look to reduce their discretionary consumption of electricity. The extent of the consumption response to higher prices is dependent on the price elasticity of demand.

Any fall in energy consumption has significant implications for EnergyAustralia's regulatory proposal as recovery of required revenue is largely dependent on the volume of energy sales. In this situation, EnergyAustralia will be unable to recover the efficient cost of meeting demand unless energy forecasts accurately reflect the consumption effect of higher prices.

Consequently, EnergyAustralia has revised its forecast to take account of the forecast of reduced demand for energy that will correspond to the 18% price impact predicted by the Department of Climate Change for 2010-11.

Other price impacts

In addition to the impact of the CPRS on household energy prices, EnergyAustralia has also considered a number of other factors that will influence the final price seen by customers.

Impact of distribution network price increases

EnergyAustralia's network charges represent an estimated 36% of final retail bills. The X-factors approved in the AER's draft determination can be used as a proxy to calculate the expected retail price increase driven by the AER's final determination. Applying the estimated 36% network/final bill ratio to the draft determination X-factors previously shown in Table 13.2 indicates that the draft determination would add 8% to retail prices in 2009-10, and 4% to retail bills in each of the following four years.

TransGrid transmission network prices

The AER itself has estimated that its draft determination for TransGrid will add 0.4% per annum to the average residential customer's annual bill.

Retail determination electricity price changes

For the purposes of the revised forecasts it was assumed that the next regulatory determination for NSW retailers will not allow significant real price increases for retailer margins. However, it is noted that IPART's current (2007) determination allows retail prices to increase by an estimated nominal 7% from July 2009, and this has been assumed to translate into a real price increase of 5% in 2009-10.

The NSW Government mini-budget

The NSW Government released its mini-budget in November 2008[217]. The mini-budget included two initiatives that EnergyAustralia considers will impact on electricity prices:

- increased coal royalties; and
- increase in levies to be recovered through distribution prices.

These two factors are estimated to add around 3% to retail prices in 2009-10.

The aggregate impact of these factors on retail prices are summarised in the following table.

[217] New South Wales, *Mini-Budget 2008-09*, 11 November 2008

Table 13.4 Assumed real retail price changes (%)

	FY10	FY11	FY12	FY13	FY14
CPRS	0.00	18.00	0.00	0.00	0.00
EA Distribution * Transmission determination	7.90	4.00	4.00	4.00	4.00
TransGrid Transmission determination	<1.00	<1.00	<1.00	<1.00	<1.00
Retail price determination	5.00	<1.00	<1.00	<1.00	<1.00
Coal royalties	2.00	0.00	0.00	0.00	0.00
DNSP levies	<1.00	0.00	0.00	0.00	0.00
Total impact	**16%**	**23%**	**5%**	**5%**	**5%**

EnergyAustralia has revised its proposal to take account of the price impact from the CPRS and the factors listed above. Based on these assumptions, retail prices over the five years of the regulatory period will increase in real terms by a compound total of 65%.

Price elasticity

The price elasticity of demand for electricity is critical to determining the size of any change in demand relative to a chance in price. EnergyAustralia has considered three independent sources for price elasticity estimates in its forecast of the likely response to higher electricity prices.

1. MMA's implied elasticities in the residential sector analysis set out in its report for the AER on EnergyAustralia's regulatory proposal.
2. MMA's analysis contained in its report for Commonwealth Treasury on the impacts of CPRS.
3. NEMMCO's recommended elasticities, as published in its Statement of Opportunities (SOO).

As noted previously, MMA's review of EnergyAustralia's June 2008 forecasts included analysis of the impact of an assumed 15% real electricity price increase between 2009 and 2014 on residential energy. The analysis indicated that the assumed price rise would induce a reduction in residential energy consumption of approximately 4% by 2013/14. EnergyAustralia assumes that MMA's analysis for Commonwealth Treasury was undertaken on the basis of similar elasticity assumptions, as both MMA reports were developed at similar times.

EnergyAustralia notes that the 4% reduction in residential energy consumption attributable to a 15% price increase in MMA's report for the AER represents an implied residential price elasticity of -0.266.

The published NEMMCO price elasticity estimates are as follows[218]:

- Residential: -0.25, and
- Commercial: -0.35

It is noted that the implied MMA elasticity of -0.266 is closely aligned with the NEMMCO residential elasticity. Given that MMA's AER report did not consider the impact of price changes on the non-residential sector, and given the alignment between the two sources of residential elasticities, EnergyAustralia considers it reasonable to rely on the NEMMCO elasticities for the purposes of the revised forecasts.

The application of the NEMMCO price elasticities to the assumed 65% price increase is that, compared with the reference (non-price impacted) forecast, energy volumes in 2013-14 are approximately 4,900 GWh or 16% lower.

Uncertainty in customer price response

The level of price rises assumed in the revised forecasts (65% over the regulatory period) is unprecedented.

It is noted that the NEMMCO price elasticity paper contains the important qualification that "These figures were estimated over a period (1980 to 1995) when electricity prices rose generally in Australia (although prices did fall gradually over the 1990s)." Given that the energy market has matured since that period, particularly with regard to gas penetration, it is possible that actual elasticities may now be lower. On the other hand, given that the magnitude of the level of price rises assumed in the

[218] NEMMCO, *Statement of Opportunities* attachment: NIEIR, *The own price elasticity of demand for electricity in NEM regions*, June 2007

revised forecasts is unprecedented (65% over the regulatory period), it is possible that the customer base's response to the price changes may be higher than the NEMMCO elasticities suggest.

A further source of uncertainty lies with the Commonwealth Government's commitment to provide low and middle income earners with additional support to meet the cost of living impacts of the CPRS[219]. There can be no certainty as to how customers will use that support. However, it could reasonably be assumed that at least a portion of the customer base will use the support to directly alleviate the CPRS impost on electricity bills, and thereby reduce the overall price elasticity compared with what it might otherwise be. Adding further uncertainty is the Commonwealth Government's commitment to provide grants and incentives to assist businesses by way of a "capital allowance program" to help in investment in more energy efficient equipment[220].

The customer base's ultimate response to the expected substantial electricity price changes cannot be known with certainty. This uncertainty is particularly relevant to the NSW distribution businesses under the WAPC form of regulation, where allowed price movements are essentially locked in for a five year period, on the basis of projections made in the year before the period begins. Should the independent elasticity assumptions used by EnergyAustralia be proven to have been too high, and customer response not be as great as modelled, then windfall gains will accrue to distributors. Conversely, if customer behaviour response is stronger than expected then the allowed revenues will be not be recouped.

For this reason, EnergyAustralia has proposed a growth factor (G factor) to ensure against significant changes in revenues as a result of energy consumption being markedly different from forecast. It should be noted that the G factor mechanism is proposed in the absence of a mechanism that allows prices to be calculated using actual energy volumes. EnergyAustralia would prefer to remove this risk to revenues using a look back mechanism. However, we note that the pass through mechanism in the Rules does not apply to energy volumes, but only to capital and operating costs. Therefore, we are forced to opt for a G factor within the control mechanism.

The mechanics of our proposed G factor is discussed in chapter 4 of Part II of this proposal.

Economic growth

Economic growth is the key input to EnergyAustralia's non-residential forecast of energy consumption and peak demand. Since EnergyAustralia submitted its proposal in June 2008, there has been a significant slowing of global economic growth and forecasts of economic growth have been updated to reflect the new market conditions.

EnergyAustralia's June 2008 volume forecasts were based on an assumed 2.6% per annum average growth in NSW Gross State Product (GSP). However, the AER's draft determination adopted MMA's recommendation that an updated economic growth outlook should be applied prior to the final determination. At the time the October 2008 revised forecasts were prepared, the most up to date economic growth forecast was KPMG Econtech's October 2008 GSP projection of 2.3% per annum for the period.

Since October 2008 EnergyAustralia has noted that more recent economic outlook projections (such as those provided by NSW Treasury[221] and ANZ Bank[222]) have been for lower growth, particularly in the short-term. Regarding the NSW Mini-Budget projections, the ANZ Bank notes that[223]:

- The [NSW Government's] economic outlook for NSW has been downgraded significantly. GSP growth is expected to be just 1.25% in 2008-09 (down from 2% previously expected and 1.5% in 2009-10, both years well below the medium term projection of 3.25%.
- Even this more pessimistic outlook looks too optimistic to us. Recent partial data suggests the NSW economy has continued to deteriorate in recent months, and is on the verge of recession (if indeed it is not already there)

[219] treasury.gov.au/cprs/html/cprs_page2.asp
[220] http://treasury.gov.au/cprs/html/cprs_page20.asp

[221] New South Wales, *Mini-Budget 2008-09*, 11 November 2008
[222] ANZ Economics and Market Research, *Economic Update*, 11 November 2008
[223] ANZ Economics and Market Research, *Economic Update*, 11 November 2008

It is considered appropriate to adopt the latest ANZ Bank projections for the near-term volume forecasts, given the ongoing emergence of actual and anecdotal data which suggests that the less recent KPMG Econtech and NEMMCO/NIEIR projections will prove to be optimistic in the short-term. The adopted GSP projections, by year are as follows:

- 0.50% GSP growth in 2008-09 (source = ANZ Bank)
- 1.25% GSP growth in 2009-10 (source = ANZ Bank)
- 2.78% growth in the ensuing four years (source = average of KPMG Econtech's October 2008 forecasts for that four year period)

The impact of the more pessimistic economic outlook is that the revised non-residential energy forecasts are 1.5% lower than the June 2008 forecasts by 2013-14.

Uncertainty in economic outlook

The current outlook for economic growth at the world, national and NSW levels is characterised by uncertainty. This uncertainty is particularly relevant to NSW distribution businesses, which are faced with the WAPC form of regulation. The current level of economic uncertainty is particularly relevant to EnergyAustralia as some two-thirds of distribution-related consumption is accounted for by the non-residential sector.

In accordance with established forecasting procedures, EnergyAustralia's revised forecasts rely on the latest available independently produced GSP projections. However, it must be recognised that the division in economic expert opinion regarding the economic outlook is at present extreme. Should the independent assumptions used by EnergyAustralia be proven to have been optimistic, then there is a risk that allowed revenues will not be recouped. Conversely, if the longer-term economic recovery is stronger than assumed, and as a consequence volumes are higher than forecast, then windfall gains will accrue to distributors.

Again, EnergyAustralia's proposal for a G factor to be incorporated into the WAPC is critical in managing the future risks to revenue that result from the highly uncertain economic conditions. This mechanism is discussed in more detail in chapter 4 of Part II of this revised proposal.

Customer Number Forecasts

The AER accepted EnergyAustralia's forecast of customer numbers. These numbers are based on work by Evans & Peck, which relates new customer numbers with dwelling approvals.

In light of the economic factors that have been reviewed for their impact on energy forecasts, EnergyAustralia has also reviewed recent forecasts of dwelling approvals. EnergyAustralia reviewed a number of forecast sources and found that there is considerable uncertainty over the timing and magnitude of the forecast housing recovery in NSW.

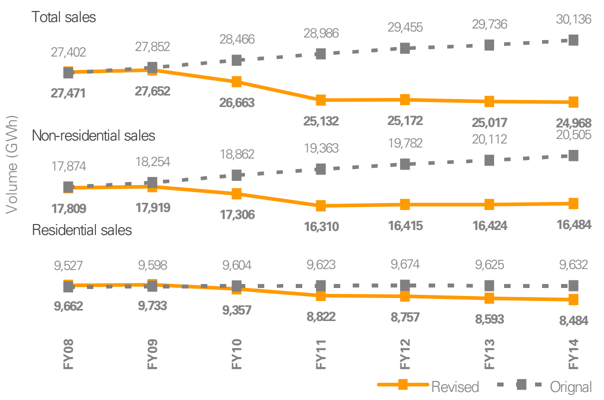
Given the divergent views with respect to dwelling approvals, EnergyAustralia does not consider that there is justification to update its forecasts of customer numbers from the updated forecasts provided to the AER in October 2008. Accordingly, EnergyAustralia accepts the AER's decision in relation to customer number forecasts.

Revised energy forecast

EnergyAustralia's 2 June 2008 regulatory proposal included the report entitled "Energy and Global Peak Demand Forecasts to 2014" as Attachment 13.2. That document set out EnergyAustralia's outlook for network volume growth at the time the June 2008 submission was made.

EnergyAustralia's revised forecast is compared with the June 2008 forecast in Figure 13.1.

Figure 13.1 EnergyAustralia's revised energy forecasts



13.3 Other revisions to X-Factors

The AER's decision on X-factors is predicated on the annual revenue requirement which is directly impacted by the AER's decisions in relation to:

- The annual revenue requirement decision (see chapter 1); and
- The rate of return decision (see chapter 8)

These decisions are in turn affected by the revisions made by EnergyAustralia to the following elements of the building block proposal:

- capital expenditure (chapter 3)
- operating expenditure (chapter 4)
- corporate income tax (chapter 12)
- depreciation (chapter 7)
- regulatory asset base (chapter 2)

EnergyAustralia's revised X-factors are shown for distribution and transmission in the following table.

Table 13.5 Revised proposal X-factors (%)

	FY10	FY11	FY12	FY13	FY14
Distribution price	-39.29	-14.29	-14.29	-14.29	-14.29
Transmission revenue	-17.08	-15.43	-15.43	-15.43	-15.43

14. Application of incentive mechanisms

SUBMISSION

EnergyAustralia has not revised its June 2008 proposal regarding:

- The application of the capital expenditure incentive mechanism.
- The application of the efficiency benefit sharing scheme (EBSS).
- The application of the service target performance incentive scheme (STPIS)
- The application of the demand management incentive scheme (DMIS).

This chapter should be read in conjunction with Chapter 14 of Part I of the June 2008 proposal, which remains EnergyAustralia's current proposal in relation to the application of incentive mechanisms.

Rule requirements

The AER's distribution determination is predicated on:

- a decision on whether depreciation for establishing the RAB as at the commencement of the following regulatory period is to be based on actual or forecast capital expenditure (Clause 6.12.1(18)).
- a decision on how any applicable efficiency benefit sharing scheme, service target performance incentive scheme, or demand management scheme is to apply to the distribution network (Clause 6.12.1(9)).

Our June 2008 building block proposal

Chapter 14 of EnergyAustralia's building block proposal sets out EnergyAustralia's proposal on the application of incentives.

Capital expenditure incentive mechanisms

EnergyAustralia proposed that regulatory (forecast) depreciation should be used when establishing the RAB as at the commencement of the following regulatory period.

Application of EBSS

EnergyAustralia proposed a safety net application of the operation of the EBSS that would allow all carry over amounts to be set to zero at the mutual agreement of the AER and EnergyAustralia.

EnergyAustralia did not seek exclusion of uncontrollable costs from the EBSS at the time of the June 2008 proposal. EnergyAustralia also proposed to identify any expenditure on non-network alternatives during the annual regulatory account processes for their exclusion from the calculation of the EBSS

Application of STPIS

EnergyAustralia proposed that the "paper trial" for the STPIS should use EnergyAustralia's annual Network Performance Report as the official audited public source for the data capture process.

Application of DMIS

EnergyAustralia proposed the continued application of the D factor scheme consistent with the AER Guideline released on 1 March 2008. It proposed an allowance for forgone revenue associated with a project eligible for D factor which continues into the next regulatory control period.

EnergyAustralia proposed processes and administrative mechanisms for the application of the DMIA. We also proposed an extension of the DMIA to incentivise network based innovations of an experimental nature which may have the effect of reducing longer term operating or capital costs ("I-factor").

AER's draft determination

Capital expenditure incentive mechanism

The AER rejected EnergyAustralia's proposal to use regulatory depreciation in establishing the RAB at the commencement of the following regulatory period. The AER decided that actual depreciation should be used to establish the opening RAB for the 2014-19 regulatory control period.

Application of EBSS

The AER did not accept EnergyAustralia's proposal to allow carryover amounts to be set to zero by mutual agreement of EnergyAustralia and the AER. It did not accept our proposal on exclusion of cost categories from the operation of the EBSS.

14. Application of incentive mechanisms (continued)

Application of STPIS

The AER did not accept EnergyAustralia's proposal use annual Network Performance Report as the official audited public source for the data capture process.

Application of DMIS

The AER decided to apply the D-factor in accordance with the approach set out in the published DMIS. The AER rejected EnergyAustralia's proposal to claim foregone revenues in the next regulatory control period for demand management projects implemented in the current period.

The AER accepted some of EnergyAustralia's proposed processes and administrative mechanisms for the DMIA but did not accept the 'i-factor'. The AER proposed a revised DMIA, subject to the agreement of NSW DNSPs.

Our response to the AER's draft determination

This chapter together with Chapter 14 of Part 1 of the June 2008 proposal now comprise EnergyAustralia's current proposal in relation to the application of incentive mechanisms.

EnergyAustralia does not agree with the AER's decisions on the application of incentive mechanisms.

- Section 14.1 notes the reasons why we do not accept the AER's reasons for rejecting EnergyAustralia's proposed application of the capital expenditure incentive mechanism.
- Section 14.2 notes the AER's decision on the application of the EBSS and indicates that the AER may provide further information in a separate submission.
- Section 14.3 provides reasons why we not accept the AER's reasons for rejecting EnergyAustralia's proposed application of the STPIS.
- Section 14.4 notes the AER's decision on the D-factor scheme. We submit that foregone revenues associated with DM projects implemented after the preparation of the demand forecasts in the regulatory proposal should be accepted in D-factor incentives claimed for each year in the 2009-2014 period.
- Section 14.5 notes that the AER's revised DMIA is a reasonable approach but that the AER should re-consider other arrangements set out in our June 2008 proposal.

14.1 Capital expenditure incentive mechanisms

The AER decided that actual depreciation should be used to establish the opening asset base for the 2014-19 regulatory control period. The AER's reasons for its decision included:

- EnergyAustralia and other NSW DNSPs appropriately identified cost drivers for the next regulatory control period and have proposed a scope of work that is commensurate with their investment needs.
- The DNSPs identified major sources of significant variances from expenditure allowances set for the current regulatory period, including expected changes in cost escalation, which have been updated by the AER using recent data. The AER considered that any variances should be minimised, and the resulting risk of windfall gains and losses should be no more than experienced by a competitive (ie: efficient) business.
- The AER considered it important to provide effective incentives for the DNSPs to seek our efficiencies where possible throughout the capital program, particularly given the significant rise in the DNSPs' capex proposals from their current historical levels.

EnergyAustralia's comments

EnergyAustralia notes the AER's decision to use actual depreciation to establish the opening asset base.

We agree with the AER that EnergyAustralia identified its cost drivers for the next period and that our scope of work is commensurate with our investment needs. This is a result of our forecasting processes which led to a prudent and efficient forecast of required capital expenditure using up to date information.

The issue we raised in our regulatory proposal relates to unexpected and uncontrollable changes in EnergyAustralia's costs over the next regulatory period. In this context, the AER needs to consider EnergyAustralia's particular circumstances including the significant investment program we will undertake over the period.

EnergyAustralia therefore considers that the AER should re-visit EnergyAustralia's June 2008 proposal to use regulated depreciation for establishing the opening asset base for the 2014-19 regulatory control period.

14.2 Application of efficiency benefit sharing scheme

The AER rejected EnergyAustralia's proposal to allow carry over amounts to be set to zero by mutual agreement of the AER and EnergyAustralia. The AER analysed the modelling of the EBSS provided by EnergyAustralia and considered that setting carry over amounts to zero would increase uncertainty and weaken the incentives provided by the EBSS.

The AER did not accept EnergyAustralia's proposal that no cost categories be excluded from the operation of the EBSS. It considered it appropriate to exclude debt raising costs, self insurance costs; insurance costs; superannuation costs relating to defined benefits and retirement schemes; and non-network alternatives.

EnergyAustralia comments

EnergyAustralia notes the AER's decision on the application of the scheme. EnergyAustralia requires more time to review the findings of the AER particularly given the complexity of the EBSS. As such, we may provide a separate submission to the AER on the EBSS.

14.3 Application of STPIS

On 29 February 2008, the AER published a final decision for the standard target performance arrangements for ACT and NSW 2009-14 regualtory period. The AER stated that it would implement a data collection and analysis exercise based on the national STPIS (placing no revenue at risk) during the 2009–14 regulatory control period. [224] The national STPIS was finalised after EnergyAustralia submitted its June 2008 proposal.

In our June 2008 proposal, EnergyAustralia noted that the most appropriate measures for data collection are those that will be common to all NSW DNSPs, are applied using constant definitions and that will demonstrate sufficient data integrity. EnergyAustralia proposed that the reliability measures contained within the DRP licence conditions satisfy those requirements.

The AER did not accept that the reliability measures contained within the DRP licence conditions should constitute the data collection exercise in the transitional STPIS. The reasons given by the AER included:

- The AER did not believe the additional costs of maintaining and reporting two sets of data to be significant, nor that these two sets of data will cause confusion.
- To allow EnergyAustralia's request, the AER would need to amend the national distribution STPIS. The AER stated it is not possible to amend the national distribution STPIS as part of the distribution determination process.

AER overlooked important detail supporting our proposal

The final National Distribution STPIS scheme was released on 26 June 2008. The reliability component of this scheme is close to, but subtly (and materially) different to the existing Schedule 2 Reliability Standards reporting requirements in the DRP licence conditions.

EnergyAustralia re-affirms its view that the STPIS reporting arrangements should use definitions, methods and exclusions consistent with those in the NSW Distribution Licence Conditions. To do otherwise will impose additional costs of reporting and maintaining two conflicting sets of data without substantive benefit to EnergyAustralia's customers.

While EnergyAustralia has not estimated the costs of complying with two sets of reporting requirements, we note that the main drivers of costs are related to potential upfront modifications to EnergyAustralia's Outage Management System (OMS) and business reporting frameworks and the subsequent ongoing burden of producing and reporting two sets of reliability measures. On 7 October 2008 we provided

[224] AER, *Final decision, Service target performance incentive arrangements for the ACT and NSW 2009 distribution determination*, 2008, p15

the AER with examples to indicate the estimated work involved in reporting different sets of reliability measures for[225]:

- Different feeder categorisation to DWE reporting (CBD feeder category definition) - this will require changes in the business reporting environment to establish two feeder categories for each feeder, one for DWE Licence Condition reporting and one for AER STPIS reporting. These two categories for each feeder will then require ongoing review and maintenance.
- Exclusions - modifications may be required to OMS as well as the reporting environment to allow for different exclusions between AER and DWE reporting. This would require an IT project to determine the best way to implement the additional reporting obligation.
- Major Event Days (MED's) - To establish AER and DWE MED thresholds separate off-line calculations would have to be performed for both AER and DWE reporting due to the use of different data exclusions and the AER prescribing additional steps in the calculation process.
  Reliability data through the regulatory period would then have to be screened against the two different regulatory MED thresholds to flag valid MED's for each jurisdiction so that those days are excluded from normalised statistics.

Irrespective of the additional costs of two reporting requirements, we consider that the AER did not provide sufficient evidence or analysis to demonstrate the benefits to customers from consistency in national standards.

In this respect we note that the incentive framework for service standards is designed to improve the performance of individual DNSPs rather than to achieve a benchmark performance standard. This is clear from the Rules which state that, in developing and implementing the STPIS, the AER must take into account the past performance of the distribution network. [226]

EnergyAustralia considers that the STPIS should be focused on improving the performance of an individual DNSP relative to its service standard obligations. This is consistent with the Rules which states that the STPIS operates concurrently with any average or minimum service standards and guaranteed service level schemes that apply to the DNSP under jurisdictional electricity legislation.[227] For EnergyAustralia, the relevant service standard obligation is the NSW DWP licence conditions. It would be rational for the AER to require EnergyAustralia to report on this information given the purpose of the STPIS.

It is not apparent how customers will benefit from information on the relative performance of DNSPs that are each subject to different obligations. Such information would simply reflect the different service standard regimes imposed by jurisdictional bodies. In these instances, the relative performance of DNSPs may be misinterpreted if DNSPs are performing to meet different system targets.

Even within a jurisdiction there can be different service standard requirements. For example, in NSW, the Schedule 2 Reliability Standards for Urban SAIDI are different between DNSP's. The 2010/11 Urban SAIDI Reliability Standard is 125 for Country Energy and 80 for both EnergyAustralia and Integral Energy[228]. Country Energy can meet its licence condition requirements with a level of Urban SAIDI that would be a breach of the Licence Conditions for both EnergyAustralia and Integral Energy.

Comparisons of DNSP service standard performance is further complicated by other factors such as the type of network, topology and random seasonal and other impacts. For example, a predominately underground network would be expected to have a fundamentally different level of performance to a largely overhead network. This may lead to further misinterpretation of the relative performance of DNSPs.

For these reasons, the AER must re-consider its decision on the STPIS reporting requirements that apply to EnergyAustralia. We have provided examples of the types of additional costs that EnergyAustralia will likely incur in meeting this regulatory

[225] Based on our record of a telephone conversation between EnergyAustralia staff and AER staff on 7 October 2008.
[226] National Electricity Rules, Clause 6.6.2(c)(3)(iii)

[227] National Electricity Rules, Clause 6.6.2(b)(2) Note.
[228] Design Reliability and Performance Licence Conditions for Distribution Network Service Providers, Schedule 2, 1 December 2007.

requirement. We have also demonstrated that there are no clear benefits from national data and that such information is likely to be misinterpreted given the differences networks and in jurisdictional obligations for service standards.

AER overlooked its ability under the Rules to apply NSW arrangements to its scheme

EnergyAustralia understands that the AER may amend or replace the STPIS from time to time in accordance with clause 6.6.2(c) of the Rules and the distribution consultation procedures. Moreover, EnergyAustralia notes that the current STPIS allows a DNSP to propose amendments to the scheme. A proposal by a DNSP to add or vary a STPIS parameter must provide information and quantitative data on its performance history covering at least the most recent three to five years as measured by its proposed parameter.

In this context, EnergyAustralia considers that the information in the annual Network Performance Reports satisfies the performance measurement requirement and accordingly, is a sufficient basis for the AER to give consideration (as its discretion under the Rules) to apply a specific scheme to NSW businesses.

14.4 D-factor element of AER's proposed DMIS

The AER proposed to apply the D-factor in accordance with the approach set out in the published DMIS.

The AER rejected EnergyAustralia's claim that demand management projects implemented in the current regulatory control period were implemented on the basis that the AER would allow recovery of associated forgone revenues into the next regulatory control period.

The AER consulted with IPART regarding their original intent, and quoted clear statements in the D-factor guidelines that limit forgone revenue claims to the current regulatory period.

The AER considered that demand management projects implemented by EnergyAustralia in the first three years of the current regulatory control period must have been implemented independent of the AER's decision to continue the D–factor scheme, or of the AER's intended operation of that scheme in future regulatory control periods.

EnergyAustralia's comments

EnergyAustralia notes the AER's position in the draft determination that forecasts in the next regulatory control period will incorporate reduced demand achieved from the implementation of DM projects in the current period to the extent these are evident at the time of making the submission.

However, impacts from demand management measures undertaken in the last two years of the regulatory control period may not be included in volume forecasts used for the next regulatory control period due to timing mismatch. Thus any DM measures implemented after this date are not considered and revenue will be forgone not only in the remainder of the current period, but for the whole of the next regulatory control period.

D-factor incentives, including revenue foregone, relating to 2007-08 and 2008-09 will be recovered in prices in the next regulatory control period. However revenue forgone in the next regulatory control arising from DM measures implemented after the submission of a regulatory proposal would never be recovered under the AER's current proposal.

EnergyAustralia considers therefore that foregone revenues associated with DM projects implemented after the preparation of the demand forecasts in the regulatory proposal be accepted in D-factor incentives claimed for each year in the 2009-2014 period.

14.5 DMIA element of DMIS

The AER's proposed an alternative approach to the DMIA, set out in AER's Demand management incentive scheme for the ACT and NSW distribution determinations incorporates EnergyAustralia's proposed approach to the application of the scheme and includes:

- an ex ante operating expenditure allowance for demand management project implementation costs over the next regulatory control period, with the recovery of any unspent or inefficiently spent allowance in the subsequent regulatory control period.
- an allowance of the same magnitude as the original scheme.
- the ability for EnergyAustralia) to recoup forgone revenues, in addition to the allowance provided under the scheme.

14. Application of incentive mechanisms (continued)

EnergyAustralia does note that the alternative arrangements do not include all of the recommendations submitted by EnergyAustralia in its building block proposal:

- The AER has not allowed for the roll-forward of unspent DMIA into the next regulatory control period;
- The AER has not accepted EnergyAustralia's proposal to include recognition for the time value of money invested in innovation projects consistent with the timing of investments in the post tax revenue model
- The AER has not accepted EnergyAustralia's proposal that the administration of the DMIA be allowed to continue into the next regulatory control period until funds are exhausted.

We would urge the AER to review these alternative arrangements. Nonetheless EnergyAustralia notes that the AER's revised proposal is a reasonable approach to most of the issues raised and will serve to achieve the objectives of the DMIA.

EnergyAustralia is disappointed that the AER missed its opportunity to pursue long term productivity initiatives using EnergyAustralia's i-factor proposal. EnergyAustralia would ask the AER to revisit the approach proposed by EnergyAustralia which builds on work already implemented in the UK.

EnergyAustralia may also provide a further submission on this issue.

15. Pass through events

SUBMISSION

EnergyAustralia has not revised its June 2008 proposal in relation to pass through.

EnergyAustralia's current proposal in relation to pass through consists of Chapter 15 of the June 2008 proposal submitted by EnergyAustralia including Attachment 15.1. This chapter 15 constitutes an interim submission and supports EnergyAustralia's current proposal.

Rule requirements

The AER's distribution determination is predicated on a decision on the additional pass through events that are to apply for the regulatory control period (Clause 6.12.1(14)).

Schedule 6.1.3(2) of the Transitional Rules provides that a building block proposal must contain a proposed pass through clause with a proposal as to the events that should be defined as pass through events.

Our June 2008 building block proposal

EnergyAustralia's June 2008 building block proposal[229] proposed 7 additional pass through events for the determination. This part of the proposal has not been revised and is still current. The proposed pass through events are:

- dead zone event;
- force majeure event;
- cost or demand input variance event;
- joint planning event;
- compliance event;
- customer connection event; and
- separation event.

EnergyAustralia has also proposed a draft pass through clause as required by Schedule 6.1.3 of the Transitional Rules.

AER's draft determination

In its draft distribution determination, the AER made the following draft decision in relation to pass-through for EnergyAustralia:

> In accordance with clause 6.12.1(14) of the transitional chapter 6 rules the AER decides that the nominated pass through events that are to apply to EnergyAustralia for the next regulatory control period are a retail project event and a force majeure event as defined in section 15.7 of the draft decision.[230]

The effect of the draft determination is that the AER has only accepted two additional pass through events proposed by NSW DNSPs - a force majeure pass through event and a retail project pass through event.

The AER rejected all other additional pass through events proposed by EnergyAustralia, along with the draft pass though clause submitted by EnergyAustralia in Attachment 15.1 of its building blocks proposal.

Our response to the AER's draft determination

EnergyAustralia does not accept the AER's decision. This chapter addresses the following matters in the AER's determination:

- Incorrect interpretation by the AER of the pass through provisions of the Transitional Rules;
- Reliance on opinion of Wilson Cook;
- Incentive framework arguments;
- Criteria applied by the AER in determining whether to include additional pass through events proposed by NSW DNSPs;
- The AER's decision in relation to the proposed compliance event;

[229] EnergyAustralia's June 2008 proposal, Chapter 15.

[230] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p287

15. Pass through events (continued)

- The AER's decision in relation to electro-magnetic fields (EMF);
- The AER's decision in relation to the proposed dead zone event;
- The AER's decision in relation to the proposed customer connection event;
- The AER's decision in relation to the proposed joint planning event;
- The AER's decision in relation to the proposed cost or demand variance event; and
- Comments on the AER's proposed draft clauses.

The National Electricity Rules envisage that additional pass through events can be designated in a distribution determination. The AER's determination as to whether additional pass through events should be designated in a determination is governed by the National Electricity Objective in section 7, and the Revenue and Pricing Principles in section 7A, of the National Electricity Law.

Specifically, the AER must have regard to the principle that NSP's should be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control network services (section 7A(2) of the Law).

We set out below some general reasons as to why EnergyAustralia believes that the AER's decisions in relation to pass through are not consistent with this principle. We also comment specifically on the AER's decisions in relation to specific pass through events referred to in the AER's draft determination.

15.1 Incorrect interpretation of the pass through provisions of the Transitional Rules

The AER has incorrectly interpreted clause 6.6.1 of the Transitional Rules relating to pass through events.

In its draft distribution determination, the AER stated:

> If the AER determines that a pass through event has occurred, the AER must determine the pass through amount and how that amount is to be recovered over the remainder of the regulatory control period.[231]

Under the Transitional Rules, the AER is not required to approve a cost pass through merely because a pass through event has occurred. In the case of a positive change event, the AER is only required to approve a cost pass through if it determines that a positive change event has occurred.[232] A positive change event occurs when:

> (a) a pass through event occurs; and
> (b) the pass through event materially increases the costs of providing direct control services.[233]

In the case of a negative change event, the AER must determine whether a negative change event has occurred.[234] In relation to a DNSP, a negative change event is a pass through event that materially reduces the costs of providing direct control services.[235] If such an event has occurred, the AER must determine whether it will impose a requirement on the provider in relation to that event, and if so, the amount and timing of the pass through.[236]

The distinction is important because each pass through event operates effectively as a gateway to accessing the pass through approval process under clause 6.6.1 of the Transitional Rules and is only a mechanism for there to be further analysis and determinations made by the AER in accordance with clause 6.6.1.

In determining the amount to be passed through, the AER must take a number of factors into account. [237] In the case of a positive change event, the AER must apply an efficiency test to the additional costs incurred or likely to be incurred.

Specifically, the AER must consider:

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[231] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p271
[232] Transitional Rules clause 6.6.1(a)
[233] Glossary, Chapter 10, National Electricity Rules
[234] Transitional Rules clause 6.6.1(b)
[235] Glossary, Chapter 10, National Electricity Rules
[236] Transitional Rules clause 6.6.1(g)
[237] Transitional Rules clause 6.6.1(j)

> the efficiency of the provider's decisions and actions in relation to the risk of a positive change event, including whether the provider has failed to take any action that could reasonably be taken to reduce the magnitude of the eligible pass through amount in respect of that positive change event and whether the provider has taken or omitted to take any action where such action or omission has increased the magnitude of the amount in respect of the positive change event. [238]

Given the steps involved in the pass through application process, designating a category of events as a pass through event does not give rise to any automatic rights to pass on increased costs to customers in relation to those events. On the contrary, the process under clause 6.6.1 of the Transitional Rules is designed to impose a series of rigorous regulatory checks and balances that preclude inappropriate risk transfer to customers.

For this reason, the AER's assumption that including additional pass through events in the determination will allow DNSPs to pass increased costs onto customers and thereby remove all risk to the DNSP involves a misapplication of the relevant provisions in the Transitional Rules and is unreasonable in the circumstances.

15.2 Reliance on opinion

The AER has relied on opinion from Wilson Cook[239] in making its draft determination in relation to pass through events.

The legal principles underlying the admissibility of expert opinion provide strong guidance as to the probative value which should be attached to expert opinion. The relevant principles are found in the common law, Uniform Evidence Acts, Federal Court Practice Direction on Expert Evidence and recent draft ACCC Part XIC guidelines for expert witnesses. The key principles include:

- The expert's report must concern a subject of specialised knowledge which can only be acquired through training, study and/or expertise[240];
- The expert's opinion must be wholly or substantially based on his/her knowledge, such that a connection can be shown between the expert's knowledge and the conclusion or opinion reached. The report should not deal with matters outside the expert's area of expertise and, where it does, the report should clearly identify any issues or questions falling outside the expert's area of expertise[241];
- The report must provide sufficient information about the expert's reasoning and the information on which he/she relied, to allow the recipient to test the accuracy and reliability of the expert's conclusions[242];
- The report should give details of materials used by the expert in preparing the report, including where information was considered but disregarded and the expert's reasons for disregarding the information[243]; and
- The report should clearly and fully state any factual assumptions relied on by the expert and distinguish the conclusions or opinions drawn from those factual assumptions[244].

In its draft distribution determination, the AER refers to the following recommendation by Wilson Cook:

> We suggest that additional pass through events not be accepted unless they are of a type that a prudent DNSP would not normally provide for in its expenditure estimates. We suggest that such proposals should meet a high threshold in that respect. In essence, we suggest that the potential events ought to be exceptional in nature. Normal or foreseeable business risks, including risks that an owner of the business ought to bear, should be excluded.[245]

Wilson Cook's opinion in relation to whether or not the AER should accept additional pass through events does not meet

[238] Transitional Rules clause 6.6.1(j)(3)
[239] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p 279

[240] Section 79 of the Evidence Act and HG v R (1999) 197 CLR 414
[241] Section 79 of the Evidence Act and HGvR (1999) 197 CLR 414
[242] Makita (Australia) Pty Ltd v Sprowles [2001] NSWCA 305;
[243] Federal Court, Practice Direction: Guidelines for Expert Witnesses in Proceedings in the Federal Court of Australia, 5 May 2005;
[244] Makita (Australia) Pty Ltd v Sprowles [2001]NSWCA 305.
[245] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 1, p13

the principles in relation to expert opinion set out above and accordingly, does not have sufficient probative value to enable the AER to rely on it for the purposes of making its decisions in relation to pass through. Specifically:

- Wilson Cook's conclusion is not a subject of specialised knowledge for Wilson Cook. In this respect, Wilson Cook has expressly disclaimed expertise and notes in its report that it has "not reviewed the pass-through events proposed by EnergyAustralia as their assessment appears to be outside our field"[246]
- Wilson Cook's conclusion is not supported by the necessary nexus between expert knowledge and opinion provided;
- Wilson Cook's report does not contain sufficient information about Wilson Cook's reasoning and the information on which Wilson Cook relied to enable the AER or EnergyAustralia to test the accuracy and reliability of Wilson Cook's conclusion in relation to pass-through events in its report.

For these reasons, EnergyAustralia submits that the AER has relied on opinion evidence that is not properly based, and in doing so, has made an error of fact in its determination in relation to pass through events.

EnergyAustralia also submits that irrespective of the issue as to the probative value of Wilson Cook's report in relation to pass through, the AER has not correctly applied Wilson Cook's opinion in any event in reaching the decisions it has made in relation to pass through. Specifically, each of the additional pass through events proposed by EnergyAustralia in its regulatory proposal:

- covers events that a prudent DNSP would not normally provide for in its expenditure estimates (and which EnergyAustralia has not in fact included in its expenditure estimates); and
- do not include normal business risks that an owner of the business ought to bear.

[246] Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs – EnergyAustralia*, October 2008, Volume 2, p65

These points are covered in more detail below.

EnergyAustralia's proposed pass through events are only "foreseeable" to the extent that they include categories of risk that are foreseeable, and are therefore capable of being encapsulated in a category covered by a proposed "pass through event". Specific events that may occur within a particular proposed pass through category are not foreseeable in terms of their occurrence, scope or timing (or a combination of these), which is why EnergyAustralia has proposed a pass through event category to cover such events.

15.3 Incentive framework arguments

The AER refers to Wilson Cook's concerns that inclusion of the introduction of smart meters as a nominated pass through event may undermine incentives for DNSPs to argue against the introduction of smart meters if they did not consider it to be cost effective[247].

The AER states that it has "similar concerns" to the concerns expressed by Wilson Cook in relation to smart meters with:

- the introduction of an emissions trading scheme;
- distribution loss event;
- retailer of last resort;
- obligations relating to EMF; and
- changes in reporting requirements.

EnergyAustralia considers there to be a fundamental flaw in the arguments presented by Wilson Cook and the AER with respect to incentives to DNSPs to argue against the introduction of new requirements in relation to the events listed above.

DNSP's investment decisions take into account numerous factors and are underpinned by a number of different drivers. EnergyAustralia's June 2008 proposal sets out EnergyAustralia's investment drivers and the processes and methodologies used by EnergyAustralia to identify network

[247] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008.

needs and make the appropriate investment decisions to meet those needs within the Rules framework.[248] The decision-making process is complex, and cost considerations are just one of many inputs into that process.

Table 15.1 highlights the key factors that influence investment decisions in relation to each of the proposed pass through events listed above.

Table 15.1 Factors influencing investment decisions

Event	Key factors influencing investment decisions
Smart metering	Efficiency benefits to entire electricity market
Introduction of an emissions trading scheme	Environmental concerns
Distribution loss event	Efficiency and environmental concerns
Retailer of last resort	Legislative and regulatory obligations or other compliance obligations
Obligations relating to EMF	Occupational health and safety and public safety obligations
Changes in reporting requirements	Legislative and regulatory obligations or other compliance obligations

Table 15.1 indicates that, with the possible exception of smart metering, investment decisions are predominantly driven by factors other than cost impacts on DNSPs.

In most cases, DNSPs are not able to significantly influence the scope or timing of an event. For example, it is not reasonable to conclude that DNSPs could influence any decision to introduce an emissions trading scheme, the timing for introduction of that scheme, or the cost effectiveness or otherwise of such a scheme.[249]

Even in the case of smart metering, cost efficiencies accrue throughout the national electricity market, including from the retail and generation sectors, which are outside the DNSP's area of expertise or sphere of influence. Accordingly, the AER's concern about the DNSPs' willingness to argue against the introduction of smart metering is unfounded as in most cases, DNSPs are not in a position to influence a decision in any event.

The AER's argument with respect to cost effectiveness is also flawed. The major benefits in relation to smart metering accrue to the retail and generation sector, while responsibility for the cost of the roll-out lies with the DNSPs. Contrary to the view expressed by the AER, if DNSPs are not provided with an opportunity to recover costs in these circumstances, there would be a strong incentive on the part of DNSPs to resist the introduction of smart metering despite the overall efficiency of the program, as DNSP costs would exceed benefits. In this respect, the AER's reasoning in relation to smart metering pass through is not consistent with the revenue and pricing principles set out in section 7A of the National Electricity Law.[250]

The AER's argument also assumes that the DNSP would have sufficient certainty at the time obligations were to be introduced of recovering its increased costs (therefore

[248] See Chapters 5 and 6 of EnergyAustralia's current regulatory proposal in particular.

[249] We note in the overview of our regulatory proposal that an emissions trading scheme impacts forecast energy volumes. There is no formal pass through allowed for increases or decreases in volumes incurred as part of government tax or scheme. However, we attempt to provide some remedy for the uncertainty of volumes in part II chapter 4 of our proposal.

[250] Clause 7A (2)(2)(a) of the National Electricity Law provides that a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services. Clause 7A(3) provides that a regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be provided includes:
(a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
(b) the efficient provision of electricity network services; and
(c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

providing the DNSP with a disincentive to argue against the introduction of an obligation that would increase its costs). Given the steps that need to be satisfied under clause 6.6.1 of the Transitional Rules before any amount can be passed on to customers, and the considerable uncertainty, even where there is a defined pass through event, as to whether increased costs can be passed on, and if so, in what amount, the AER's conclusion in this respect is not reasonable.

EnergyAustralia also submits that the AER has made an error of fact in its determination in relation to the above events by relying on, and extrapolating Wilson Cook's conclusions in relation to smart meters to other proposed pass through events, when Wilson Cook's opinion evidence is not probative in this respect.

Further, under the National Electricity Law, the AER is required to provide reasons for suggesting that the distribution determination should be made as proposed, including the draft constituent decisions.[251] The reasons given by the AER for a draft distribution determination must set out the basis and rationale of the determination including:

- details of any assumptions made by the AER in undertaking any material qualitative and quantitative analyses; and
- reasons for the making of any decisions, the giving or withholding of any approvals, and the exercise of any discretions referred to in Chapter 6, for the purposes of the determination.[252]

EnergyAustralia submits that the AER has failed to set out the assumptions it has made in exercising its discretion, and reasons for each of its decisions in relation to pass through. The AER has simply reflected Wilson Cook's statement in its decision in relation to additional pass through events covering the introduction of an emissions trading scheme, a distribution loss event, retailer of last resort, obligations relating to EMF and changes in reporting requirements. In the absence of a probative opinion from Wilson Cook in this respect, and the failure by the AER to provide alternative reasons, EnergyAustralia submits that the AER's decision in this respect is incorrect and unreasonable in the circumstances.

Additionally, EnergyAustralia notes that DNSPs are required to comply with the capital and operating expenditure objectives in the Rules, and to meet prudency and efficiency requirements in relation to their investment decisions. A prudent DSNP takes a number of commercial and business considerations, including the interests of its customers, and the community more generally, into account in making its investment decisions. In fact, one of EnergyAustralia's stated objectives under the *Energy Services Corporation Act* 1995 is to "exhibit a sense of social responsibility by having regard to the community in which [EnergyAustralia] operates".

It is inconsistent with the regulatory framework in which DNSPs operate, and with sound business practice, for a DNSP to make a decision solely, or primarily, on the basis of whether costs can be passed through to customers.

15.4 Criteria applied by the AER

The AER has stated that it has taken the following criteria into account in determining whether or not to include an event proposed by the NSW DNSPs as a pass through event.

- the event is already captured by the event definitions;
- the event is clearly identified;
- the event is uncontrollable. That is, a prudent service provider through its actions could not have reasonably prevented or substantially mitigated the event;
- despite the event being foreseeable, the timing and/or cost impact of the event could not be reasonably forecast by the relevant NSW DNSP at the time of submitting its regulatory proposal;
- the event is not already insured for (either external of self-insured);
- the event cannot be self-insured because a self-insurance premium cannot be calculated or the potential loss to the DNSP is catastrophic;
- the party who is in the best position to manage the risk is bearing the risk; and

[251] National Electricity Rules 6.10.2(3)
[252] National Electricity Rules 6.12.2

- the passing through of costs associated with the event would undermine the incentive arrangements within the regulatory regime.

Although it has proposed these criteria as the basis on which it has made a decision as to whether or not to include an event as a pass through event in the determination, the AER has not demonstrated how it has applied these criteria in its decision making process. Specifically:

- the AER has not sufficiently demonstrated how these criteria have been taken into account in reaching a decision on each of EnergyAustralia's proposed pass through events.;
- the AER has not explained the weight given to each of the criteria in reaching a decision in relation to the proposed additional pass through events, or made it clear whether a criterion has a negative or positive weighting;
- the AER has not explained how a decision has been affected if more than one criterion applies or how a decision is affected if the application of criteria result in inconsistent outcomes;
- in some cases, the AER has made errors of fact in determining whether a proposed additional pass through event complies with these criteria; and
- the AER has applied the criteria inconsistently with other parts of the determination [253]

Application of the AER's criteria to EnergyAustralia's proposed pass through events is considered in more detail below.

Compliance event

As the definitions in the Rules of "regulatory change event" and "service change event" (both of which are pass through events in the Rules) do not capture all of the compliance obligations that apply to EnergyAustralia in running its business and its network, EnergyAustralia proposed that the AER include in its determination a "compliance event" as an additional pass through event.

[253] For example, see comments on self-insurance under the heading "AER's draft clauses" in section 15.7.

In its proposal, EnergyAustralia summarised a "compliance event" as follows:

> an event other than a service standard event or a regulatory change event involving:
>
> - a change in a compliance obligation (meaning a general law obligation or a requirement of a non-mandatory code, standard or guideline which represents standards acceptable to the workforce or to the community); or
> - a change in the way a compliance obligation is interpreted; or
> - any new compliance obligation, which materially increases or decreases the cost to EnergyAustralia of providing Standard Control Services including Prescribed (Transmission) Standard Control Services.[254]

In its draft determination, the AER comments in relation to compliance events that:

> …how the DNSPs respond to events of this nature, such as court decisions, is a matter for the management of the DNSP. While the DNSP may not be able to control the outcome of the event, if it decides to change its operation, then it is at the discretion of management. In those cases, the DNSP has some control over its expenditure. [255]

This conclusion is fundamentally incorrect. DNSPs are required to comply with the law, including court decisions, and management does not have a discretion to act unlawfully or in breach of court orders. For this reason, it is not reasonable for the AER to conclude that a DNSP has a discretion to change its operation, when that change is required to comply with the law.

Failure to comply with a court order or direction may constitute contempt of court and make EnergyAustralia and/or its directors and officers liable to fines and/or imprisonment.

A decision to act unlawfully or in breach of a court order may also be negligent in the circumstances, particularly where public or workplace safety is concerned. Any such decision would have major ramifications for directors and officers of EnergyAustralia.

[254] EnergyAustralia's June 2008 proposal, p164.
[255] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, pp281-82

Company directors and officers also have duties under common law, including a duty to exercise their powers and discharge their duties in good faith in the best interests of the corporation, and for a proper purpose. Various civil, and in some cases, criminal, penalties attach for breach of these duties. Further, as directors and officers of a Statutory State Owned Corporation[256], EnergyAustralia's managers are under a statutory duty to exercise reasonable care and diligence in performing their functions and powers.[257] Directors and officers face a fine of up to $11,000 for breach of this duty.

Depending on the circumstances, failure to act in accordance with court decisions or relevant standards may be negligent and attract penalties under statute and/or at common law.

EnergyAustralia submits that the AER's conclusion that the DNSP would have some control over its expenditure in these circumstances is not relevant to the issue in question. The key issue is that the DNSP has no control over the event itself, as it must comply with the law. In these circumstances, the fact that the DNSP may have some control over its expenditure in responding to the event, is not relevant to the decision as to whether the event should be designated as a pass through event.

EnergyAustralia submits that its proposed compliance event meets the criteria set out by the AER in its draft distribution determination as follows:

- the event is not already captured by the definition of "pass through event" in the Rules, for the reasons set out in our response to questions from the AER dated 5 August 2008 attached as Attachment 15A;
- the event is clearly identified in EnergyAustralia's current regulatory proposal;
- the event is uncontrollable. EnergyAustralia is not in control of court decisions, or the imposition of standards or like requirements in circumstances other than those captured by a service standard event or a regulatory change event, and is unable to take any action to reasonably prevent or mitigate such an event. On the contrary, EnergyAustralia submits that a prudent service provider would take those steps necessary to comply with such requirements;
- although the event itself (ie. that there may be court decisions, court orders or other compliance requirements imposed on the business) in broad terms is foreseeable, the timing and/or cost impact of the event could not be reasonably forecast by the relevant DNSP at the time of submitting its regulatory proposal (and for this reason, cannot reasonably be included in the DNSP's expenditure forecasts);
- the event is not already insured for (either external or self-insured);
- the event cannot be self-insured because a self-insurance premium cannot be calculated;
- the party who is in the best position to manage the risk is bearing the risk. EnergyAustralia is required to manage the compliance risk in relation to such events, and without an additional pass through event covering compliance events, inevitably EnergyAustralia will be required to bear the full risk and cost impacts if such events occur. Given such events are "uncontrollable", and otherwise meet the AER's criteria in relation to additional pass through events, EnergyAustralia submits that the AER's decision not to include a compliance event as an additional pass through event in its determination is unreasonable; and
- as compliance with such events is not discretionary, the passing through of costs associated with such events would not undermine the incentive arrangements within the regulatory regime.

EnergyAustralia:

- does not accept the AER's decision in relation to its proposed compliance event; and
- submits that its proposed compliance event meets the AER's pass through event criteria and should be included as a pass through event in the distribution determination.

EMF event

In its draft determination, the AER refers to Integral Energy's proposed EMF event, defined as follows:

[256] As defined in State Owned Corporations Act 1989 (NSW), section 3 and Schedule 5

[257] State Owned Corporations Act 1989 (NSW), section 33A(1) and schedule 10, section 3(3).

> An electric and magnetic fields event occurs if during the course of the regulatory control period, either of the following types of events occur:
>
> (a) Integral Energy becomes liable for any claims directly related to electric and magnetic fields from any of the assets it owns and operates or has owned or has owned or operated including claims by present and former employees of Integral Energy and/or third parties; or
>
> (b) the manner in which Integral Energy undertakes "live line" work is affected due to the potential exposure of the people undertaking this work to electric and magnetic fields, and as a consequence of that event, the costs to Integral Energy of providing direct control services are materially increased.

EnergyAustralia considers that an EMF event as referred to in the draft distribution determination would fall within the category of EnergyAustralia's proposed compliance event. In fact, EnergyAustralia's definition of "compliance obligation", which is included in EnergyAustralia's definition of its proposed compliance event[258], specifically makes reference to EMF.

EnergyAustralia's view is that any changes to EMF standards may have a material impact on the costs to EnergyAustralia of providing direct control services, because of the potential substantial impact on working methods (particularly in relation to live line work) and the need to mitigate EMF risks in relation to both existing and future infrastructure.

The AER has indicated in its draft determination that it considers the policy intent of the NER is that such events (eg. changes to ARPANSA standards) would be covered by the *regulatory change event* pass through category. As explained in EnergyAustralia's response to the AER dated 5 August 2008 and attached as Attachment 15A, a *regulatory change event* is defined by reference to a *regulatory obligation or requirement*, which is defined in clause 2D(1) of the National Electricity Law. EnergyAustralia's view is that the definition of *regulatory obligation or requirement* is unlikely to extend beyond obligations whose ultimate source is under statute.

Changes in legal obligations arising as a result of a court decision, or new standard may raise the bar in terms of the standard of care required for EnergyAustralia to discharge its existing duty of care obligations, expand the scope of EnergyAustralia's duty of care obligations, or impact on EnergyAustralia's ability to meet its legislated corporate objectives. In terms of workplace and business impact, a new EMF standard from ARPANSA could have significant impacts on the way in which EnergyAustralia plans, constructs and maintains its network, and result in a significant increase in the costs to EnergyAustralia of providing direct control services. EnergyAustralia submits that it is consistent with the policy objectives of the NEL, and with the national electricity objective in particular, that DNSPs should be able to recover at least the efficient costs in complying with new legal obligations arising from court decisions or the introduction of new standards. This is particularly the case where investment costs associated with compliance are high and there is a potential workplace or public safety impact.

EnergyAustralia considers that the AER's decision in relation to EnergyAustralia's proposed compliance event and Integral Energy's proposed EMF event arises from a misinterpretation of the definition of *regulatory change event* in the Rules, is not consistent with the policy objectives of the NEL (insofar as the NEL allows for recovery by the DNSP of at least the efficient costs of complying with other legal obligations), and is unreasonable in the circumstances.

Dead zone event

In its current regulatory proposal, EnergyAustralia proposed a "dead zone event" as an additional pass through event, to ensure that otherwise legitimate cost pass throughs for the 2009-2014 regulatory control period would not be precluded solely on the basis of the timing of the event giving rise to those changes in costs.

In summary, a dead zone event is any pass through event that occurs during the 2004-2009 regulatory control period that has a cost impact in the 2009-2014 regulatory control period, that has not been included in EnergyAustralia expenditure forecasts (as accepted or substituted by the AER) for that period.

The AER comments that it does not accept EnergyAustralia's proposed dead zone event because:

- it is inconsistent with the NER; and
- a DNSP could delay submission of its application until the next regulatory control period.

[258] Attachment 15.1, clause 2(e) of EnergyAustralia's regulatory proposal.

15. Pass through events (continued)

Chapter 10 of the NER defines a *regulatory change event*, a *service standard event* and a *tax change event* as follows.

A *regulatory change event* is:

> A change in a regulatory obligation or requirement that:
>
> (a) falls within no other category of pass through event; and
> (b) occurs during the course of a regulatory control period; and
> (c) substantially affects the manner in which the Transmission Network Service Provider provides prescribed transmission services or the Distribution Network Service Provider provides direct control services (as the case requires); and
> (d) materially increases or materially decreases the costs of providing those services.

A *service standard event* is:

> A legislative or administrative act or decision that:
>
> (a) has the effect of:
>
> (i) substantially varying, during the course of a regulatory control period, the manner in which the Transmission Network Service Provider is required to provide a prescribed transmission service, or a Distribution Network Service Provider is required to provide a direct control service; or
> (ii) imposing, removing or varying, during the course of a regulatory control period, minimum service standards applicable to prescribed transmission services or direct control services; or
> (iii) altering, during the course of a regulatory control period, the nature or scope of the prescribed transmission services or direct control services, provided by the service provider; and
>
> (b) materially increases or materially decreases the costs to the service provider of providing prescribed transmission services or direct control services.

A *tax change event* occurs if:

> (a) any of the following occurs during the course of a regulatory control period for a Transmission Network Service Provider or a Distribution Network Service Provider:
>
> (i) a change in a relevant tax, in the application or official interpretation of a relevant tax, in the rate of a relevant tax, or in the way a relevant tax is calculated;
> (ii) the removal of a relevant tax;
> (iii) the imposition of a relevant tax; and
>
> (b) in consequence, the costs to the service provider of providing prescribed transmission services or direct control services are materially increased or decreased.

EnergyAustralia's interpretation of these definitions in the Rules is that an event occurring under any of the above three pass through categories must occur "during the course of a regulatory control period" to be captured by the relevant pass through event definition.

EnergyAustralia's concern is that the relevant "regulatory control period" for the purposes of the above definitions is the regulatory control period in which the relevant event occurs. The effect of this is that if an event (that would otherwise be a *regulatory change event*, a *service standard event* or a *tax change event*) occurs during the current regulatory period, but its cost impact is in the next regulatory period, it will not be caught by any of these pass through event definitions For this reason, it is not possible to delay submission of an application (in relation to any of these defined pass through events that occur before the 2009-2014 regulatory control period) until the 2009-2014 regulatory control period, as the Rules do not provide any mechanism for making that application.

For example, if an event that would otherwise fall within the definition of *regulatory change event* occurred on 28 February 2009, which resulted in changes to the costs of providing direct control services from 2010, EnergyAustralia would be unable to pass through any of the resultant cost increases because:

- the impact of such an event would not have been included in EnergyAustralia's [revised] regulatory proposal;
- the event would have occurred outside the 2009-2014 regulatory control period, so would not be a pass through event within that period; and
- as the impacts of the event occur outside of the 2004-2009 regulatory control period a pass through application within the current period would provide no relief for costs within the 2009-2014 period.

Accordingly, the AER's conclusion that EnergyAustralia's proposed dead zone event is inconsistent with the NER is a misconstruction of the relevant principles in the Rules.

EnergyAustralia submits that its proposed dead zone event meets the following criteria set out by the AER in its draft determination:

- the event is not already captured by the defined event definitions, as the defined event definitions do not cater for events occurring within the current regulatory control period that have cost impacts in the next regulatory control period;
- the event is clearly identified within EnergyAustralia's regulatory proposal;
- the event is not within EnergyAustralia's control, and prudent action by EnergyAustralia would neither prevent or substantially mitigate the event;
- although the event as a category is foreseeable (at least in the broad sense that as a category of pass through event, its occurrence is sufficiently foreseeable to enable EnergyAustralia to include it as a proposed pass through event in its proposal), the timing and/or cost impact of the event could not be forecast by EnergyAustralia at the time of submitting its proposal (because it occurs after that time);
- EnergyAustralia is not the party in the best position to manage the risk, as not only does it have no control over the risk, but is being required to bear risk that it would not otherwise be required to bear under the Rules (if not for a technical drafting issue in the drafting of the pass through event definitions); and
- as such events are non-discretionary in terms of timing (and but for a drafting issue in the Rules, would otherwise be captured as defined events), the passing through of costs associated with such events would not undermine the incentive arrangements within the regulatory regime.

For the above reasons, EnergyAustralia does not accept the AER's decision in relation to EnergyAustralia's proposed dead zone event. EnergyAustralia submits that the AER has made an error of fact by misinterpreting and misapplying the relevant provisions in the Rules, and that the AER's decision is unreasonable in all the circumstances.

EnergyAustralia also notes that if a dead zone event occurs, it will occur before 1 July 2009, and possibly before the AER makes its determination. It is possible that the 90 day period in which EnergyAustralia may seek approval of the AER to pass through a positive pass through amount under clause 6.6.1(c) of the Transitional Rules may elapse before the determination is in place, or shortly after it is in place.

To address this issue, EnergyAustralia proposes, and requests that the AER considers, that either:

(a) each positive change event in relation to a dead zone event be deemed to have occurred on 1 July 2009; or

(b) the period for submitting an application to the AER for approval to pass through a positive pass through amount in relation to a dead zone event be 90 business days from 1 July 2009, rather than 90 business days from the date the relevant positive change event occurs.

Customer Connection Event

In its current regulatory proposal, EnergyAustralia has proposed a "customer connection event" as an additional pass through event, to cover any material increases in costs associated with the augmentation of the network to meet a large transmission or subtransmission network connection requirement or to establish a new substation to supply load requested by a developer or end use customer.

Although the grounds on which the AER has rejected EnergyAustralia's proposed customer connection event are not entirely clear, it seems as though the customer connection event has been rejected on the basis that the AER considers that:

- it would be inappropriate for the DNSP's customers to bear the risk of any deviations from forecast capital projects during the next regulatory control period; and
- allowing costs to be passed through to customers would undermine incentives on the part of EnergyAustralia either unilaterally or in conjunction with TransGrid or other DNSPs, to undertake prudent and efficient planning activities.

EnergyAustralia's proposed customer connection event would only apply to customer connection requirements that are either unforeseen at the time of forecasting, or are not sufficiently certain at that time (in terms of timing, scope or likelihood of occurring) to be forecast with sufficient accuracy. The proposed customer connection pass through event would not apply to customer connection requirements that are sufficiently certain to have been included in EnergyAustralia's expenditure forecasts for the regulatory control period.

This type of event is conceptually the same as the contingent project regime provided in relation to transmission under

15. Pass through events (continued)

Chapter 6A of the Rules. In fact, in its 2005 determination for EnergyAustralia, the ACCC expressly made provision for a contingent project determination for major customer connections arising from identified customer requirements in certain circumstances. [259]

Neither the transitional Chapter 6 Rules or Chapter 6 have a contingent project regime. However, at the time the MCE developed both sets of Chapter 6 Rules, there was a clear intention that the additional pass through mechanism would provide an equivalent opportunity for the costs of unforeseen major customer connections to be recovered. This is demonstrated in the MCE's Explanatory Statement issued in April 2007 with the Chapter 6 Rules.[260] A table in the MCE's statement describes the differences in approach between transmission and distribution. Items 7 and 8 specifically address cost pass through and contingent projects. In the explanation as to why the contingent project regime has not been applied to distribution, it states that uncertain projects may be accommodated by pass through.

This view was reinforced by the MCE in its response to consultation on the Chapter 6 Rules[261]. The SCO clearly states (at page 29) that "uncertainty around capex projects can be dealt with via the pass through provisions to the extent that the DNSP can demonstrate that the event is outside its control"

EnergyAustralia seeks a pass through event for costs associated with customer connections on the basis that those events are outside its control. EnergyAustralia is unable to plan for new customer connections that are not firm requirements at the time it makes it capital expenditure forecasts. Accordingly, in the event of any of the increased costs associated with customer connections being passed through to customers, those customers would not be bearing the risk of "deviations from capital forecasts", because the costs of the specific customer connection requirement in question would not have been included in those forecasts. This is precisely the reason EnergyAustralia seeks a pass through event for this category of expenditure as it is unforeseen, could not reasonably have been foreseen, and is outside EnergyAustralia's control.

EnergyAustralia also rejects the AER's conclusion that allowing a customer connection event as a pass through event would undermine incentives on the part of EnergyAustralia to undertake "prudent and efficient planning activities".

EnergyAustralia's forecast expenditure for the regulatory control period is the expenditure EnergyAustralia considers reasonably reflects its requirements in order to achieve the capital and operating expenditure objectives under the Transitional Rules. The expenditure must also reasonably reflect the efficient costs of achieving the capital and operating expenditure objectives and the costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the capital and operating expenditure objectives.

EnergyAustralia's view is that to have included a provision for costs associated with unknown, and therefore unquantifiable, customer connection requirements in its expenditure forecasts would not represent a reasonable forecast of costs, could not be demonstrated as prudent and efficient and would not have been justifiable within the Rules framework.

Costs associated with major new customer connections can be significant, and can have substantial impacts on the cost of providing direct control services during the regulatory control period. For example, there have been proposals over a number of years for major customer loads (over 100 MVA) in the Kurri area. Although the proposals are not sufficiently advanced to constitute firm requirements (and therefore cannot be included in EnergyAustralia's capital expenditure forecasts), if they proceed, there is likely to be a significant increase in the costs to EnergyAustralia of providing direct control services during the 2009- 2014 regulatory control period.

Similarly, if the proposed metro railway line was to be re-introduced as a result of a change in government policy, the impact on EnergyAustralia would be considerable. EnergyAustralia's expectation is that if the metro rail line was

[259] ie. where the regulatory test assessment requires shared network augmentations, the shared augmentation is material and provision has not been made for that shared augmentation in other projects.

[260] Changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution – Explanatory Material, SOC/MCE April 2007.

[261] SCO Response to Stakeholder comments on the Exposure Draft of the National Electricity Rules for distribution and revenue pricing – MCE/SCO August 2007.

introduced, there would be an increase in demand on EnergyAustralia's inner metropolitan system equivalent to almost one year's load growth. Although EnergyAustralia could recover shallow connection costs in relation to such a project, the project demand would have a significant impact on the timing of augmentations to the transmission system and require the timing of augmentation of shared assets to be brought forward.

EnergyAustralia submits that its proposed customer connection event meets the following criteria set out by the AER in is draft distribution determination:

- the event is not already captured by the defined event definitions;
- the event is clearly identified in EnergyAustralia's regulatory proposal;
- the event is uncontrollable and EnergyAustralia acting as a prudent service provider could not have taken any actions to reasonably prevent or mitigate the event. EnergyAustralia does not have control over new customer connection requirements;
- despite it being foreseeable in general terms that new customer connections may be required during the 2009 - 2014 regulatory control period, specific customer connection requirements are either not foreseeable, or not sufficiently certain at the time the proposal is submitted to justify a DNSP, acting prudently, to include those costs in its expenditure forecasts;
- the event cannot be self-insured;
- failure to make provision to enable the DNSP to recover its increased costs in these circumstances means that the DNSP is bearing all the risk of a new customer connection; and
- as such events are non-discretionary and outside EnergyAustralia's control, the ability to potentially pass through costs associated with the event would not undermine the incentive arrangements within the regulatory regime.

EnergyAustralia submits that the AER has misapplied its own criteria in reaching a decision not to include EnergyAustralia's proposed customer connection event as a pass through event in its distribution determination and does not accept the AER's decision in this respect.

Joint planning event

In its draft distribution determination, the AER has rejected EnergyAustralia's proposed joint planning event as a pass through event for the same reasons that it rejected EnergyAustralia's proposed customer connection event, namely that in the AER's view:

- it would be inappropriate for the DNSP's customers to bear the risks of any deviations from forecast capital projects during the next regulatory control period; and
- allowing costs to be passed through to customers would undermine incentives on the part of EnergyAustralia, either unilaterally or in conjunction with TransGrid or other DNSPs, to undertake prudent and efficient planning activities.

EnergyAustralia included a joint planning event as a pass through event to address:

- changes in the allocation of responsibilities (and costs) as between EnergyAustralia and a planning partner in relation to a capital project beyond EnergyAustralia's reasonable control; and
- new requirements that arise during a capital project that are beyond EnergyAustralia's reasonable control.

EnergyAustralia's assets include both transmission and distribution components. EnergyAustralia's capital submission includes significant expenditure attributable to projects which are jointly planned with other NSPs.

Joint planning decisions involve the economic evaluation of alternatives, and expenditure is generally required by all participants in the joint planning process. The allocation of responsibilities and expenditure requirements as between each of the participants in a jointly planned project can vary substantially between available options.

The current regulatory determination process provides a mechanism for cost recovery for jointly planned projects only in situations where:

- the various regulatory determinations for the participants in that joint planning process provide project funding for all parties involved in a joint project; and

15. Pass through events (continued)

- the project option contained in a regulatory submission, and for which funding is provided in a determination, is ultimately constructed.

Disincentives to efficient network development can arise where:

- as a result of detailed project development subsequent to the regulatory determination, it becomes necessary to build an alternative project option, which changes the allocation of responsibilities and costs between the participants; and
- the various regulatory determinations for the participants involved in joint planning do not provide the requisite funding for all parties involved in the development of the project.

These issues are explained in more detail below.

Cost Allocation

At the time of the regulatory submissions, many projects are not fully developed and submissions are based on the most cost effective solution at that time. For jointly planned projects, the usual practice is that each party includes a request for funding to cover its part of the works.

Issues arise where an alternative project option, involving a different share of costs between the parties, is subsequently found to be the least cost option. Where there are material differences in the cost allocation between parties, proceeding with the least cost option can result in over-expenditure by one party, and under-expenditure by the other against their relevant determinations. The current regulatory regime makes no allowance for this issue, with the result that one party ends up being penalised for efficient planning.

For example, the project to replace the 132kV busbar at TransGrid's Beaconsfield West 330/132kV substation is driven by the busbar condition. At the time EnergyAustralia submitted its regulatory proposal, the proposed method of construction involved TransGrid constructing a new busbar adjacent to the existing equipment, and extending the busbar trunking from EnergyAustralia's feeders to the new busbar. This would have required relatively minor work by EnergyAustralia. However, there are now doubts that the proposed solution is the least cost alternative. A likely possible alternative is the construction of a new busbar by TransGrid, requiring EnergyAustralia to divert its cables to the new busbar. This will involve substantial additional cost to EnergyAustralia.

Inconsistency between determinations

Where regulatory determinations for parties involved in joint planning are inconsistent (ie. where funding is provided for one party but not the other in relation to jointly planned works), there is significant pressure on the joint planning process to provide sub-optimal or delayed solutions. This issue has arisen in relation to the current determination. The joint development strategy for the Sydney CBD relied on the advancement of TransGrid's 330kV supply to the inner metropolitan area to enable the retirement of poorly performing EnergyAustralia132kV cables. This strategy was reviewed by Wilson Cook and EnergyAustralia's expenditure included in the AER's draft determination. It should be noted that EnergyAustralia's expenditure on this project is relatively minor as work by TransGrid avoids the need for an estimated $138 million in cable replacement.

TransGrid included in its submission a contingent project (CBD Supply) for the advancement of the 330kV cable to the CBD to cater for its portion of this work. This contingent project has not been accepted by the AER in TransGrid's draft determination. If funding is not provided to TransGrid in the AER's final determination, then there will be a substantial impediment to the implementation of the most cost effective solution.

Both the above examples (ie: cost allocation and inconsistency between determinations) demonstrate how factors outside EnergyAustralia's control can provide a disincentive to efficient development of the network. EnergyAustralia submits that it is reasonable in these circumstances, and consistent with the policy objectives of the NEL, for EnergyAustralia to be able to apply to recover associated costs through a pass through mechanism.

EnergyAustralia submits that its proposed joint planning event meets the following criteria set out by the AER in is draft distribution determination:

- the event is not already captured by the pass through event definitions;
- the event is clearly identified within EnergyAustralia's regulatory proposal ;

- the event is uncontrollable. EnergyAustralia is not reasonably able to control the outcomes of joint investigations, and attendant changes in allocation of responsibilities and costs between participants, or the decisions of regulators;
- the timing and/or cost impact of the event could not be reasonably forecast by EnergyAustralia at the time of submitting its regulatory proposal;
- the event is not already insured for (either external of self-insured);
- the event cannot be self-insured because in such cases a self-insurance premium cannot be calculated;
- if the AER allowed a joint planning event as a pass through event, it would assist in ensuring that the party who is in the best position to manage the risk is bearing the risk; and
- as such events are non-discretionary, the passing through of costs associated with such events would not undermine the incentive arrangements within the regulatory regime. On the contrary, the absence of a pass through provision reflecting EnergyAustralia's proposed joint planning event undermines the incentives for joint planning participants to act prudently and implement the most efficient and cost effective solution.

For these reasons, EnergyAustralia does not accept the AER's decision not to include a joint planning pass through event in its distribution determination and submits that the AER's decision in this respect is unreasonable.

15.6 Cost or demand variance event

In its current regulatory proposal, EnergyAustralia has proposed an additional pass through event to cover variances in actual cost movements or demand for the regulatory control period from cost movements or peak demand forecasts used in the capital and operating expenditure forecasts for that period. The purpose of EnergyAustralia's proposed "cost or demand input variance event" is to cover unexpected or unforeseeable changes in demand or cost movements that either trigger new investments or materially alter the costs of current or planned investments.

In its draft distribution determination, the AER has rejected EnergyAustralia's proposed cost or demand variance event on the basis that:

> …incentives to produce robust estimates and minimise costs may be undermined if variations to normal business costs and demand are included as pass through events.[262]

EnergyAustralia submits that as its proposed cost or demand input variance event only applies where cost or demand variance has a *material* impact on the cost of providing direct control services, it does not apply in circumstances involving "variations to normal business costs and demand". The AER's decision to reject the proposed pass through event on this basis is unreasonable in the circumstances. Further, the Rules framework sets out capital and operating expenditure objectives for DNSPs and requires them to demonstrate prudency and efficiency in their investment decisions. This regulatory framework imposes obligations on DNSPs that override any incentive-based approach to forecasting.

The AER also comments that it does not accept the "pass through event" as proposed because of the "general nature of the proposed input costs event".[263] Under the NEL, the reasons given by the AER for a draft distribution determination must set out the basis and rationale of the determination, including:

- details of any assumptions made by the AER in undertaking any material qualitative and quantitative analyses; and
- reasons for the making of any decisions, the giving or withholding of any approvals and the exercise of any of the discretions referred to in Chapter 6, for the purposes of the determination.[264]

EnergyAustralia submits that the AER's broad references to the "general nature of the proposed input costs event" do not meet these requirements under the NEL.

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[262] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008,p 285
[263] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008,p 285
[264] National Electricity Rules 6.12.2

15. Pass through events (continued)

Despite rejecting the proposed input costs event, the AER has indicated a willingness to consider any specific events, provided compliance with the AER's criteria proposed in 15.6.1 can be demonstrated. [265] The AER does not make it clear whether it will consider these events in the context of an additional pass through event category covering cost input events, and if so, the terms of that additional pass through event category. In the absence of a pass through event category covering cost variance, the mechanism by which the AER will consider any such specific events is unclear.

Considerable effort has been devoted in previous regulatory determinations and the current draft determination to the assessment of real cost escalators.[266] The methodology employed in determining such escalators combines an independent forecast of movements in the price of input components with weightings of expenditure. The use of the real cost escalation methodology arose as a result of a realisation that CPI no longer reflected a realistic expectation of the movement of some costs experienced by NSPs.

The current economic circumstances have resulted in rapid changes in key cost factors such as commodity prices and exchange rates. Although the AER's final decision will take into account the latest cost escalation data, there is a substantial risk that real escalators will change over the next regulatory control period from the forecast figures, with significant impacts on costs.

The AER's escalators are targeted at meeting the AER's obligations to provide businesses with a reasonable opportunity to recover efficient costs. If this objective is met, there would be a reasonable expectation that costs may increase or decrease above the forecast escalators, resulting in either a loss of value to DNSPs (if costs increased) or a loss of value to customers(if costs decreased).

Energy Australia believe a cost variance pass through targeted at addressing the impacts of variations in real cost escalators would be compliant with the criteria proposed by the AER as.

- the event is not already captured by the event definitions (EnergyAustralia would be willing to work with the AER to clearly define this event);
- the event is uncontrollable. Factors such as exchange rates and commodity prices are clearly outside the control of NSPs. The AER would not have previously allowed for the impact of real cost escalation if such factors had been controllable;
- the timing and/or cost impact of the event could not be reasonably forecast by EnergyAustralia at the time of submitting its regulatory proposal;
- the event is not already insured for (either external of self-insured);
- the event cannot be self-insured
- if the event was included as a pass through event in the determination, it would facilitate the party who is in the best position to manage the risk to bear the risk; and
- as such events are non-discretionary, the passing through of costs associated with such events would not undermine the incentive arrangements within the regulatory regime.

EnergyAustralia's view is that inclusion of a pass through event covering variations to costs arising from changes to real cost would help ensure an equitable outcome for NSPs and customers should significant changes occur to real cost escalators over the next period.

EnergyAustralia proposes that it works together with the AER to develop requirements which are acceptable to both parties.

15.7 AER's proposed draft clauses

The AER has accepted two additional pass through events in its draft determination. These are a:

- retail project event; and
- force majeure event.

The AER has proposed drafting for each of these events.

Neither of these events captures in its entirety EnergyAustralia's proposed force majeure and separation

[265] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November, p 285.
[266] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p530

events and the drafting does not reflect EnergyAustralia's drafting for either of these additional pass through events.

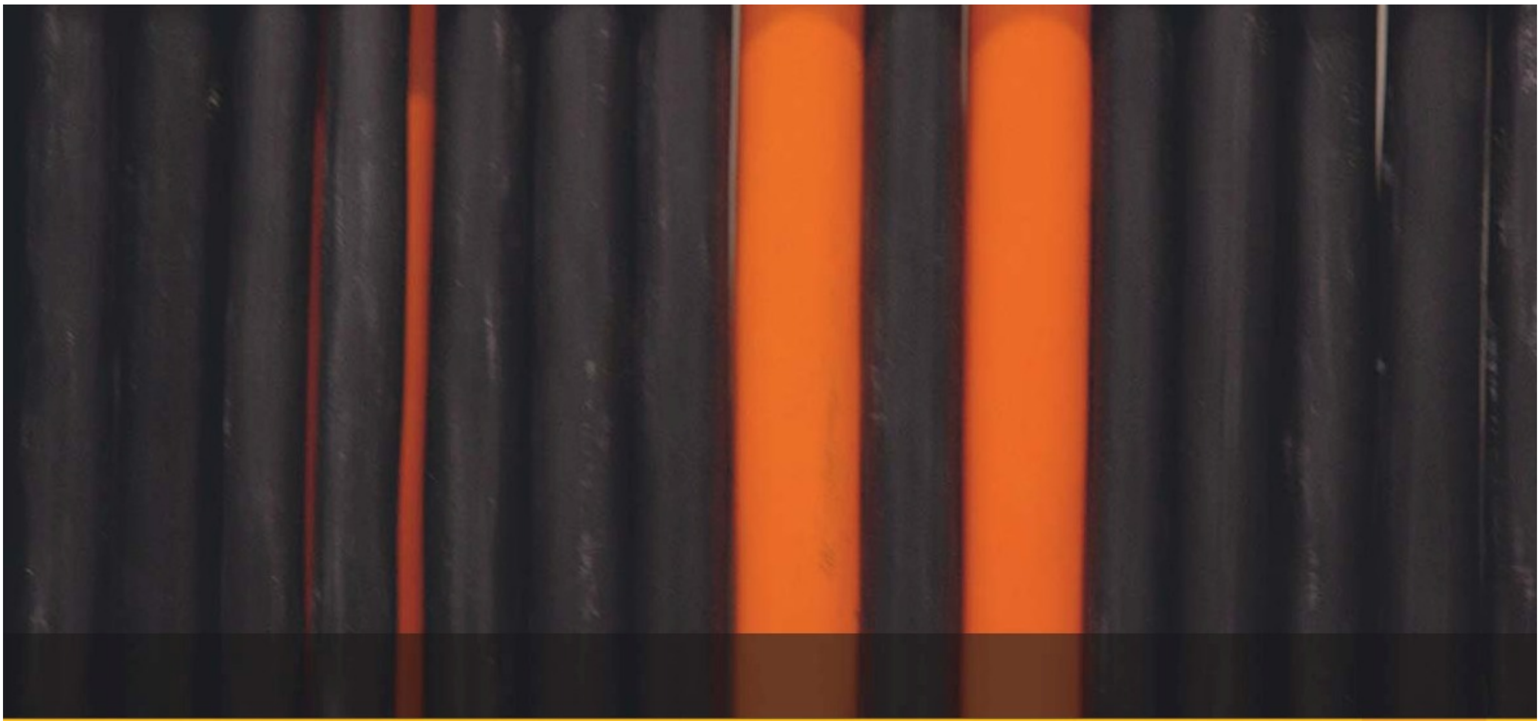
For example, the drafting of retail project event refers to a material change in the costs to the DNSP of "providing direct control services in the next regulatory control period". The effect of this is that DNSPs could only potentially recover increased costs incurred in providing direct control services in the 2014-2019 regulatory control period.

The AER has amended the drafting of EnergyAustralia's proposed force majeure clause to exclude insurable events (defined as "that is events for which external or self-insurance is feasible"). It has also excluded the reference to including prescribed transmission standard control services.

The reference to "events for which external or self-insurance is feasible" is problematic for a number of reasons, namely:

- lack of clarity as to the meaning of "feasible in this context; and
- in its draft determination, the AER has rejected many of EnergyAustralia's self insurance claims with several reasons for rejection being given. EnergyAustralia submits that where the AER has rejected a self insurance claim on the basis of the robustness of EnergyAustralia's calculation as to the likelihood of occurrence of the event in question, then costs in relation to that event (that would otherwise have been covered by self-insurance) should be able to be recovered under the force majeure pass through provisions.

..



Part II – Services classification and control mechanism proposal

1-2. Service classification

SUBMISSION

EnergyAustralia has not revised its June 2008 proposal seeking to vary the classification of some services which are currently classified as standard control services.

EnergyAustralia's current proposal in relation to the classification of services is comprised in chapters 1 and 2 and Attachments 1.1 and 1.2 of Part II of the June 2008 proposal. This chapter is EnergyAustralia's response to the draft determination and supports EnergyAustralia's current proposal.

Rule requirements

The AER's distribution determination is predicated on a decision on the classification of services to be provided by DNSPs (Clause 6.12.1 (1)).

Clauses 6.2.3A and 6.2.3B apply deemed classifications to distribution services provided by NSW DNSPs, but the AER may vary the deemed classification under clause 6.2.3B(i) when making a distribution determination for a NSW DNSP with the agreement of that DNSP.

Our June 2008 proposal

EnergyAustralia proposed to change the classification of all services deemed by clause 6.2.3B(b) to be classified as unregulated services.

AER's draft determination

The AER addressed the classification of services in section 2 of its draft determination, specifically addressing EnergyAustralia's proposal at sections 2.3 and 2.5 and setting out its decision at section 2.6. While not formally accepting or refusing to accept any particular aspects of our proposal, the AER classified EnergyAustralia's distribution services in accordance with the deemed classification under the Rules.

The AER did not vary the classification of services on the basis that:

- It did not consider that EnergyAustralia had provided sufficient information to satisfy the AER that the services should be reclassified;
- EnergyAustralia did not apply to IPART to reclassify the services during the current regulatory control period;
- The AER believes there is a strong presumption in the Rules for greater, rather than less, regulation of unregulated distribution services; and
- It would be more appropriate to consider the classification of these services in the 2014-19 regulatory control period.

In addition, the AER rejected EnergyAustralia's proposal for an additional miscellaneous service disconnection at the meter box via fuse removal.

Our response to the AER's draft determination

EnergyAustralia does not accept the AER's decision. It has addressed the following matters in the AER's determination.

- Section 1.1 sets out the reasons why EnergyAustralia does not accept the AER's conclusion that there was insufficient information to allow the AER to vary the classification of these services.
- Section 1.2 sets out the reasons why EnergyAustralia considers that the AER has not provided adequate reasons for its decision as required by the Rules.
- Section 1.3 sets out the reasons why EnergyAustralia's decision not to apply to IPART to have these services reclassified is irrelevant for the AER's own determination and submits that in any case the AER has not actually considered the level of regulation actually applied by IPART.
- Section 1.4 sets out the reasons why EnergyAustralia does not accept the AER's claim of a strong presumption in favour of not reclassifying services.
- Section 1.5 sets out the reasons why EnergyAustralia does not support the AER's delay in considering the reclassification of services.

With respect to the AER rejecting the proposal for an additional miscellaneous service – disconnection at the meter box via fuse removal – EnergyAustralia notes and accepts the AER's decision.

1.1 Information to support varying service classifications

The AER did not consider that EnergyAustralia had provided sufficient information to satisfy the AER:

- that emergency and recoverable works and customer specific services are not distribution services; and
- that a different classification for metering services (types 1-4), customer funded connection, customer specific services and emergency recoverable works is clearly more appropriate for the next regulatory control period.

The AER also stated it was mindful of the impact a decision to reclassify certain services may have on specific customer groups, and that the scope for competitive service provision also needs to be reviewed.

EnergyAustralia's comments

EnergyAustralia provided a comprehensive proposal in favour of varying the classification of services

Chapter 2 of Part II of EnergyAustralia's June 2008 proposal contained a very detailed assessment of the reasons why EnergyAustralia believed it was appropriate for either the classification of certain services to be varied or for those services not to be treated as distribution services at all:

- Metering services for Types 1-4 meters have been subject to competition for over a decade, since before the commencement of the NEM. EnergyAustralia's share of this activity across the NEM is around 15% and the majority of the metering providers are not regulated;
- Customer funded connections have also been subject to active competition for a similar period. EnergyAustralia's share of this work within its territory is 25% and diminishing, with other providers unregulated;

A detailed review of the nature of customer specific services concluded that these services were not distribution services as they were neither provided "by means of" nor "in connection with" a distribution system; and

The nature of emergency recoverable works and the associated legal implications were dealt with in Attachment 2.1 of Part II to our June 2008 proposal. These services do not fall within the category of "distribution services".

EnergyAustralia had no reason to believe that the AER did not have sufficient information upon which to make a decision in relation to EnergyAustralia's proposal with regard to the classification of services. Extensive discussions have taken place between EnergyAustralia and the AER and its consultants during their review of EnergyAustralia's proposal. This included hundreds of questions and answers, however the AER did not take the opportunity to seek any further information or clarification in relation to EnergyAustralia's proposal to vary the classification of services.

Whether or not certain services are distribution services is a matter of legal analysis

EnergyAustralia submitted a detailed analysis of why customer specific services and emergency recoverable works did not fall within the meaning of distribution services in the Rules. It is clear from EnergyAustralia's proposal that the proposal with respect to these services relies upon what is essentially legal analysis. This analysis should be considered and tested by the AER as part of its consideration of EnergyAustralia's proposal. It is not apparent to EnergyAustralia what additional analysis or information would be required to satisfy the AER of these matters, given that the matter could be determined on the basis of what is essentially a regulatory legal argument or analysis.

In relation to emergency recoverable works, the AER commented that:

> The AER has not been satisfied that emergency recoverable works is not a distribution service and notes the example given by EnergyAustralia is unlikely to be able to be performed by another entity.[267]

[267] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November, p52.

However, whether or not those works are likely to be able to be performed by another entity is not relevant to the question of whether or not such services are distribution services, and as such it is an irrelevant consideration.

The question of whether or not certain services are "distribution services" at all (within the meaning of the Rules) is a legal question of construction, and it is not a matter which the AER ultimately has jurisdiction to determine – although we would prefer the AER to formally note the construction we have submitted. Ultimately, however, the AER's opinion on the matter is not determinative.

1.2 The AER's reasons for its decision

It appears that the AER did not consider the substance of EnergyAustralia's proposal at all, but rather put forward reasons why the AER did not consider the substance of EnergyAustralia's proposal.

EnergyAustralia's comments

The AER did not accept or reject any of the points raised in our proposal and did not provide substantive reasons (apart from process) in not varying the proposal

EnergyAustralia is of the view that the AER was incorrect in not considering EnergyAustralia's proposal with respect to the classification of its services. The AER was required to make a decision in relation to the classification of services which impacts on EnergyAustralia. EnergyAustralia has the right to put forward a different classification and a more general right to be heard in relation to the classification decision and to have its views taken into account.

Furthermore, the AER's draft decision in section 2.6 is not supported by analysis or discussion of the relevant material that was contained in EnergyAustralia's proposal. The AER has clearly not addressed the substantive issues in EnergyAustralia's submission, and has failed to provide adequate reasons for its decision (as required by clauses 6.10.2(3), 6.11.2 and 6.12.2).

As a matter of general principle, in order for reasons to be adequate, they must adopt a clear process of reasoning to allow a proper understanding of the basis upon which the decision has been reached. Reasons are inadequate if it is impossible to deduce the reasoning from the information provided – as opposed to, for example, merely the options considered and ultimate conclusion reached.

The AER summarised its reasoning as simply:

> The AER does not consider EnergyAustralia to have provided sufficient justification to satisfy the AER that these services be reclassified to an unclassified service and not be subject to regulation.[268]

While some further detail was provided in the body of the document, this was largely in relation to the AER's desire to defer consideration of the issues.

EnergyAustralia notes that in this context the AER referred to inadequate "justification", whereas elsewhere the AER referred to inadequate "information". It is not clear whether these words were intended to be interchangeable. We have addressed the issue of the adequacy or otherwise of EnergyAustralia's information in section 1.1 above. As to "justification", it is not clear what would constitute sufficient justification in the absence of the AER fully considering the substance of EnergyAustralia's submissions. Is the AER saying that no matter what merit there may have been in those submissions, the other considerations outlined (eg presumption for greater regulation, desire to defer the decision etc) were always going to be more persuasive? If so, it is not clear how the AER can reach this conclusion without properly assessing the material presented by EnergyAustralia and then weighing it up against those other considerations.

As a further matter of general principle, a failure to adequately consider or take into account important evidence and arguments can constitute a failure to engage with the case advanced. "Engaging" requires a proper grappling with the evidence and arguments. A mere recitation of them is not sufficient.

The AER's failure to give adequate reasons and to engage with the arguments also leads to the inference that the AER has fallen short of its obligation to take into account all relevant

[268] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, pxix.

considerations in its decision. Furthermore, a failure to respond to substantial issues raised may amount to a denial of procedural fairness, as it can indicate that the AER has failed to deal with the proposal presented to it by EnergyAustralia.

1.3 EnergyAustralia's approach in the current regulatory control period

The AER noted that EnergyAustralia had the opportunity to apply to IPART during the current regulatory control period for a change in the regulation of excluded services. This would have involved EnergyAustralia satisfying IPART's competition test. IPART would no longer subject these services to regulation if the competition test was satisfied.

The AER noted that EnergyAustralia had not taken the opportunity to apply to IPART and this was an influencing factor in its decision not to vary the classification of the service.

EnergyAustralia's comments

IPART's approach to consideration of the classification of services is irrelevant to the AER's decision on whether to vary the classification

IPART determined in 2004 that the regulatory provisions that it applied to excluded services would have been waived for those services that satisfied a "competition test". Such reclassification would not, however, have been relevant for emergency and recoverable works or customer specific services.

During the course of the 2004-09 determination, EnergyAustralia did give consideration to whether to apply to IPART to reclassify metering Types 1-4 services. Details were sought from IPART on what such a test would entail. EnergyAustralia concluded that because of the complexity of the proposed test, the resources which would have been required to mount a case for reclassification were not warranted. Moreover, EnergyAustralia believed that IPART would not look favourably on such an application prior to the implementation of a new framework.

Notwithstanding this history, IPART's approach to the reclassification of such services is irrelevant to the AER's consideration of EnergyAustralia's proposal. The AER has an obligation to properly consider EnergyAustralia's proposal within the current regulatory framework of the NEL and Rules.

It should also be noted that, unlike IPART's 2004 determination, there is no flexibility for the AER to review the classification of services during the period of the 2009-14 determination.

The AER has not considered the level of regulation that IPART actually applied to excluded services during the 2004-09 determination

In its 2004 determination, IPART regulated excluded distribution services under the Regulation of Excluded Distribution Services Rule, subject to the following provisions:

- Pricing of services was subject to pricing principles;
- Information disclosure requirements were to apply; and
- Price monitoring arrangements were to be established.

All of these provisions would have been waived for services that satisfied a "competition test".

Subsequent to the IPART Determination, in December 2004 EnergyAustralia published information disclosure for its excluded services, covering the first two points above. IPART did not appear to implement price monitoring during the course of the determination.

It should have been noted by the AER, that the level of regulation that was applied by IPART to excluded services during the course of the 2004-09 determination was so light handed as to be virtually non-existent. In this circumstance, it was not warranted to commit significant resources to satisfy the requirements of a competition test.

EnergyAustralia believes that in making its draft determination to reject the reclassification of some services, the AER should have paid regard to the level of regulation actually applied by IPART during the 2004-09 determination.

1.4 No presumption in favour of not reclassifying services

The AER's decision not to vary the classification was based on its understanding that the Transitional Rules indicate:

- a clear presumption that certain services provided by DNSPs are distribution services;
- a strong presumption that services will follow the deemed classification unless the DNSP can satisfy the AER that a different classification is clearly more appropriate; and
- a preference for greater, rather than less, regulation of such unregulated distribution services.

EnergyAustralia's comments

The AER's interpretation of the Transitional Rules is incorrect

The fact that the Rules suggest that certain services previously classified by IPART might initially be classified as distribution services does not relieve the AER of the obligation to be satisfied that such services are in fact distribution services, particularly where a detailed analysis has been submitted which casts doubt on that classification.

EnergyAustralia does not agree with the AER's assertion of a "strong" presumption in the Transitional Rules that services will follow the deemed classification unless a DNSP can satisfy the AER that a different classification is "clearly" appropriate. The Rules simply provide for the AER to decide to apply a different classification. The AER must be satisfied that it is appropriate to do so, but no particular threshold or level of satisfaction is required before the AER may apply a different classification. However even if there was such a presumption, the AER acknowledges that such a presumption would be displaced if the AER was satisfied that a different classification is more appropriate.

EnergyAustralia believes it has advanced cogent arguments which should satisfy the AER that it is appropriate to vary the classification of services. However the AER has erred in refusing to give those arguments proper consideration because it has taken the view that it would be more appropriate to consider them as part of the "normal framework and approach paper".

EnergyAustralia also disputes the AER's assertion that the Transitional Rules indicate a preference for greater, rather than less, regulation. It is incumbent on the AER to have regard to sound regulatory practice in its decision making. In this regard, the Expert Panel stated: "Less intrusive forms of regulation or no regulation at all are warranted where there is evidence of potential or actual competition sufficient to discipline the conduct of incumbent service providers and the barriers to entry are modest or low."[269] This is quite clearly the case with EnergyAustralia's provision of Connection and Metering Type 1-4 services.

Moreover, the Transitional Rules have been framed with regard to the form of regulation factors set out in section 2F of the NEL. These factors specify the considerations which apply in determining where services should be directly controlled. Those factors do not imply any preference for greater, rather than less, regulation in any circumstance.

The AER has not properly assessed whether such presumptions (if any) should be displaced

Even if there were any such presumptions in the Rules, they would be only presumptions which can be outweighed. The AER cannot properly be in a position to decide whether or not any such presumptions are outweighed in the absence of properly considering and engaging with the substance of EnergyAustralia's arguments.

1.5 The AER's decision to delay consideration of the issue

The AER is of the view that it would be more appropriate to consider any proposed change in 2014-19 as part of the normal framework and approach paper process which applies to distribution determinations made under chapter 6 of the NER.

EnergyAustralia's comments

There is no reason to delay consideration of the issues

EnergyAustralia reiterates that the AER has not properly considered the issues we raised in our proposal in support of the reclassification of services. The Transitional Rules confer a responsibility on the AER to consider the issues involved and it

[269] Expert Panel On Energy Access Pricing Report to the Ministerial Council On Energy, April 2006, p51

1-2. Service classification (continued)

is not acceptable for the AER to defer that consideration "due to truncated timelines"[270]. The AER has an obligation to consider and make a decision on the material that has been put before it and has acted unreasonably by delaying proper consideration of the issues for five years.

Whilst many of the arguments that EnergyAustralia has articulated would apply equally to other DNSPs, some do not. This is in part reflected by the differing positions adopted by the other NSW and ACT DNSPs. For example, the level of competition in the provision of connection services differs markedly with the DNSP's territory and the applicable jurisdictional arrangements. There are similar differences in respect of the provision of Types 1-4 metering services. Therefore, as each DNSP's situation differs, it is not appropriate for the AER to defer the consideration of service reclassification issues to permit a group of DNSPs to be reviewed together.

For the above reasons, EnergyAustralia believes there is no reason why our proposed changes to the classification of services cannot be given the appropriate level of consideration as part of the AER's 2009 determination.

[270] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p18

3. Negotiable Components of Direct Control Services

SUBMISSION

EnergyAustralia has not revised its original proposed approach for identifying those components of direct control services which are negotiable components.

This chapter is EnergyAustralia's submission in relation to the AER's draft determination and addresses the reasons why EnergyAustralia has not changed its June 2008 proposal in light of the draft determination. Consequently chapter 3 of Part II of the June 2008 proposal is EnergyAustralia's current proposal in relation to negotiable components of direct control services supported by this chapter.

Rule requirements

The AER's distribution determination is predicated on a decision by the AER on which, if any, components of Direct Control Services are negotiable components.
(Clause 6.12.1 (16A)).

Our June 2008 proposal

EnergyAustralia's Service Classification proposal (Part II, chapter 3) included those components of direct control services which EnergyAustralia considers should be negotiable components. EnergyAustralia's proposed approach to describing the negotiable components of Direct Control Services is based on a set of criteria against which the component can be tested and includes an indicative list. The proposed criteria are as follows:

> A negotiable component of a Direct Control Service will be any component of that service (or a condition of the service) where some variability can be applied to the provision of the Direct Control Service without interfering with or in any way compromising EnergyAustralia's ability to comply with any regulatory obligation or requirement as that term is defined in the National Electricity Law and may include the following types of matters:
>
> - location of substation to support customer load;
> - location of customer's connection to network and point of entry to the premises, and location of metering
> - voltage levels of customer's connection;
> - assessment of customer's load requirement;
> - availability of standby supply from the EnergyAustralia grid when on-site generation is unavailable;
> - capacity of customer's connection before augmentation or other works will be required; and
> - design planning criteria which exceeds the applicable security standard.

Negotiable components of a direct control service will be subject to a negotiating framework under Part DA of the Transitional Rules.

AER's draft determination

Whilst not formally rejecting EnergyAustralia's proposal, the AER has decided to define a negotiable component of a direct control service as any component (or the terms and conditions on which that direct control service or component are provided) where:

- the direct control service exceeds the network performance requirements which it is required to meet under any jurisdictional electricity legislation;
- the direct control service, except to the extent of any prescribed requirements of jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as set out in schedule 5.1a or 5.1 of the NER; or
- the direct control service is a connection service provided to serve network users at a single distribution network connection point, other than connection services that are provided by one network service provider to another network service provider to connect their networks where neither provider is a market network service provider.

Our response to the AER's draft determination

EnergyAustralia does not accept the AER's decision. This chapter addresses the following matters in the AER's determination:

- Section 3.1 outlines why the definition proposed by the AER is inconsistent with EnergyAustralia's proposal and appears to be inconsistent with the AER's own reasoning and analysis.

3. Negotiable Components of Direct Control Services (continued)

- Section 3.2 notes the inconsistencies between the AER's definition and the MCE's policy intent.
- Section 3.3 outlines why the AER's definition appears to be inconsistent with other aspects of the regulatory framework.

3.1 Consistency with EnergyAustralia's proposal and the AER's own analysis

In its draft determination regarding the negotiable components of EnergyAustralia's direct control services, the AER:

- accepted EnergyAustralia's claim that it will be difficult to define in advance which components of the service will be negotiable and that the same service component could be negotiable for one customer but not for the other;
- considered it inappropriate to specify any particular components as negotiable components;
- decided to allow flexibility for the customer and the DNSP to identify negotiable components on a case by case basis;
- envisages that only sophisticated customers of the NSW DNSPs wound seek to negotiate for services of this kind;
- concluded that such negotiations would only occur in a small number of circumstances and only in relation to a small element of the total service;
- quotes an example provided by EnergyAustralia relating to a customer seeking a variation to the location of a substation to support a customer's load;
- notes that in developing a definition for negotiable components of a direct control service, the AER acknowledges that it is important that a negotiable component does not interfere with any regulatory obligation or requirement; and
- is mindful of the need to keep arrangements simplified.

EnergyAustralia agrees with the AER's issues and considerations. We believe our proposal is consistent with all the conclusions reached in the AER's analysis.

The AER did not formally reject EnergyAustralia's proposed negotiable components.

Instead it applied its own definition believing it to be consistent with the examples of potential negotiable components provided by EnergyAustralia.

The AER decided to define a negotiable component of a direct control service as any component of a direct control service where:

- the direct control service exceeds the network performance requirements which the direct control service is required to meet under any jurisdictional electricity legislation;
- the direct control service, except to the extent of any prescribed requirements of the jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as set out in schedule 5.1a or 5.1 of the NER; or
- the direct control service is a connection service provided to serve network users at a single distribution connection point.

The AER's definition in its draft determination seems to contradict the conclusions in its analysis and considerations in section 3.2.4 of its draft determination. EnergyAustralia submits that the AER should revisit its considerations and revise its definition, preferably in line with what EnergyAustralia proposed in its June 2008 proposal.

We outline below some of our concerns with applying the AER's definition, notably:

- the AER's definition leads to a much broader outcome than envisaged by EnergyAustralia's proposal and the AER's analysis; and
- at the same time, the definition is not wide enough to cover all the examples proposed by EnergyAustralia.

AER's definition is broader than what EnergyAustralia Proposed

Above and below standard services

The AER's first and second bullet points of its proposed definition are:

- the direct control service exceeds the network performance requirements which it is required to meet under any jurisdictional electricity legislation; and

- the direct control service, except to the extent of any prescribed requirements of jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as set out in schedule 5.1a or 5.1 of the NER.

EnergyAustralia agrees that there should be some mechanism to allow it to recover the cost of additional network augmentations provided at the request of the customer, in order to provide a standard of service that is higher than that required by relevant regulatory instruments – for example, "N-2". We believe this example is also covered by EnergyAustralia's own definition.

However, EnergyAustralia also notes that under IPART's Capital Contributions Determination[271], the trigger for whether or not a customer should pay for network augmentations is not based on whether network performance requirements are exceeded. There is no reference to network performance requirements at all in that determination. Rather, the general rule is that a DNSP must pay for network augmentations, subject to particular rules regarding large load and rural customers.

Therefore, should a customer require an "N-2" reliability arrangement (where the relevant network elements are network augmentations), and the customer is not a rural or a large load customer, the customer would effectively fund the additional augmentation through increased charges. The classification of negotiable components of direct control services does not currently accommodate this.

EnergyAustralia notes that there are some ambiguities around what constitutes the relevant "network performance requirements". For example, Schedule 5.1 of the Rules prescribes very little in relation to network reliability. (A detailed analysis of this aspect is beyond the scope of this submission.)

[271] IPART Determination "Capital Contributions and Repayments for Connections to Electricity Distribution Networks in NSW, Determination No 1, April 2002"

EnergyAustralia also notes that many of the aspects of the connection service, set out in the bullet point list below, are also relevant to network augmentations, but are not caught by the AER's proposed definition.

For example, if a rural or a large load customer funds a network augmentation under IPART's Capital Contributions Determination, or if a customer funds above standard network augmentations (eg N-2) through additional NUoS charges, or if a generator funds network augmentations, then many of the aspects of the connection service set out in the bullet point list section below will be equally applicable to network augmentations. However, they would not be captured by any of the three bullet points comprising the AER's definition

EnergyAustralia's proposal also allowed for negotiated services arrangements to apply to public lighting services. The range of negotiable components of direct control services which EnergyAustralia proposed would also apply in many cases to public lighting customers.

Connections

The AER's third bullet point of its proposed definition is:

> the direct control service is a connection service provided to serve network users at a single distribution network connection point, other than connection services that are provided by one network service provider to another network service provider to connect their networks where neither provider is a market network service provider.

This third limb is extremely broad and capable of capturing or impacting upon just about every aspect of the "connection service".

EnergyAustralia can only assume that the term "connection service", used in this context, is intended to have the definition in Chapter 10 of the Rules. That definition is as follows:

> An *entry service* (being a service provided to serve a *Generator* or a group of *Generators*, or a *Network Service Provider* or a group of *Network Service Providers*, at a single *connection point*) or an *exit service* (being a service provided to serve a *Transmission Customer* or *Distribution Customer* or a group of *Transmission Customers* or *Distribution Customers*, or a *Network Service Provider* or a group of *Network Service Providers*, at a single *connection point*).

3. Negotiable Components of Direct Control Services

(continued)

This is not to be confused with the term "Customer Funded Connections" under IPART's 2004 network determination, which has a different meaning.[272]

In the Rules, the meaning of "connection service" is difficult to interpret. Arguably it is literally capable of covering most network services, as most such services are provided to network end-users (customers and generators) at their respective connection points. However, given the context of this and other terminology in the Rules, it is fairly clear that this is intended to relate only to this service insofar as it is provided by assets that are dedicated to serving that connection point (as opposed to shared network assets).

Despite this distinction between dedicated and shared, a network user does not experience distinct services, but rather one integrated service. Furthermore, prior to connection, there is a complex layering of services within services or conditions of service, but the user experiences one seamless service on connection.

The process of connecting a new customer or generator ("user") may involve (among other things):

- the DNSP undertaking technical studies to assess the suitability of the connection;
- decisions regarding which new assets (dedicated and/or shared) will be constructed to accommodate the connection;
- decisions regarding which of those assets are to be funded by the user and which by the DNSP;
- the DNSP preparing a design brief for new assets to be constructed (and subsequent certification of that design);
- negotiations on aspects of design, location etc;
- design and construction of new capital works (at the user's cost) by the DNSP or an ASP (for contestable works);
- design and construction of new capital works (at the DNSP's cost) by the DNSP;
- specifying requirements for related property and environmental aspects of the new works (eg easements, approvals);
- establishment of the various commercial and technical aspects of the connection agreement (which may involve aspects of negotiation, including on other charges for generators under clause 5.5(f)(4)); and
- allowing the user to import and export power to and from the distribution system via existing and new assets (once the new assets are commissioned).

For ease of reference the above list is referred to as "the bullet point list".

As a minimum, if the AER continues with the use of its proposed definition, it should clarify that the following are excluded from the above list of connection services. (The basis for this is explained further in section 3.3):

- the design and construction of new capital works funded by the user (as they are not direct control services in the first place);
- monopoly services (as they are covered by separately regulated prices) including undertaking technical studies, design and design certification for large load customers[273]; and
- decisions regarding which of the new capital works (to be constructed to accommodate a new connection) are to be funded by the user and which by the DNSP (as they are covered by IPART's Capital Contributions Determination, and provided that an equivalent set of regulatory principles is developed to cover generator connections).

[272] IPART's term by contrast, refers only to the (contestable) design and construction of certain funded assets- not to other aspects of the service to be provided by those assets. IPART's term also extends to the design and construction of shared augmentations as well as dedicated assets. Further, IPART's definition does not extend to any aspect of service provided by those assets not so funded.

[273] For generator connections, these studies are undertaken by the DNSP as a NSP obligation under the Rules and charges are on a cost recovery basis in accordance with the rules, see Rules 5.2 and 5.3.

If the above services are excluded the only services left in the list that might be subject to negotiations on price are:

- related property and environmental aspects of the new works (eg easements, approvals) – to the extent that the DNSP undertakes those aspects at the customer's cost;
- charges for generators under clause 5.5(f)(4) of the Rules; and
- use of system charges, for allowing the user to import and export power to and from the distribution system via existing and new assets.

EnergyAustralia does not object to services provided in relation to related property and environmental aspects of the new works being classified as a negotiable component of a direct control service as it most likely would have been covered in its own definition. Although generally environmental consultants and surveyors are selected and funded by the customer on a contestable basis and carry out their services for the customer to meet the minimum technical and other requirements specified by EnergyAustralia to ensure the safety and security of the network and that EnergyAustralia meets its other regulatory obligations and requirements.

If a substantial dedicated network extension is required to be built in order to accommodate a new connection (customer or generator), EnergyAustralia may require as a condition of connection that the user, in addition to procuring and funding the dedicated works, ensures that the works to be handed over have all necessary approvals and associated easements. However, the user may require EnergyAustralia to do these things or provide assistance in relation to them, or EnergyAustralia may need to do things on its own behalf in relation to these things.

EnergyAustralia also does not object to charges for generators under clause 5.5(f)(4) being negotiable components of direct control services, although there appear to be significant ambiguities over what this means and how it is to be applied, and it almost never arises in practice. (A detailed analysis of this aspect is beyond the scope of this submission)

The remaining aspects of the connection services in the list above largely relate to non price related matters, for example, negotiations on asset location, or commercial terms and conditions of access.

EnergyAustralia does not object to such non price-related matters being negotiable components of direct control services. However, EnergyAustralia wishes to ensure that there is no confusion created in network users, noting that the negotiable component principles, negotiable component criteria and negotiating framework focus largely (although not exclusively) on price. There should be sufficient flexibility in the approach to allow EnergyAustralia to tailor informative documents that enable customers to understand what is negotiable under the framework and what is not.

The AER's definition does not include everything that EnergyAustralia's definition includes

Connections - AER's example of substation location

EnergyAustralia disagrees with the AER's claim that its proposed definition is consistent with the examples given by EnergyAustralia.

The AER references one of EnergyAustralia's examples in relation to negotiations on substation location. Section 28 of the *Electricity Supply Act 1995* (NSW) provides as follows:

> 28 Transformers
>
> (1) This section applies if, in the opinion of the distribution network service provider, the supply of electricity required by a customer:
>
> (a) exceeds that which can be provided by a service line from its street mains, and
> (b) can best be given by installing transformers, switchgear or other equipment on the premises to be supplied
>
> (2) In such a case, the distribution network service provider may require the customer to provide for use by the distribution network service provider, free of cost, a place within those premises to accommodate the transformers, switchgear or other equipment that the distribution network service provider considers should be installed.
>
> (3) The place provided must be approved by, and must be enclosed in a manner approved by, the distribution network service provider.

As with most other capital works required for the connection of a customer, the question of who should fund the capital cost of the substation is largely determined by reference to IPART's Capital Contributions Determination.

Section 28 of the *Electricity Supply Act 1995* (NSW), on the other hand, is effectively about the additional non-monetary consideration, provided by a customer, of land (or an appropriate interest in land) to accommodate the substation. This is in addition to any capital contribution to the cost of the substation itself.

In practice, the need for an additional substation is triggered every so often by the next customer once the capacity limit of relevant existing substations are reached. It is not necessarily related to the size of the particular customer's load.

This situation has been identified by the AER and is a good practical instance of an area for negotiation encountered by EnergyAustralia in the context of customer connections. Of course, the principle in section 28 is not up for negotiation, but alternative arrangements are sometimes reached regarding the requirements of the substation and its location. The results of negotiations in this regard will impact on price in the sense of the total cost of the connection to the customer, but it would not involve negotiations on price (in the sense of money payable to EnergyAustralia). Rather, the negotiations relate to the location of the asset.

If any components of EnergyAustralia's direct control services were to be categorised as negotiable, this aspect would appear to be a fair candidate (provided that it is very clear that nothing in Part DA derogates from or casts doubt upon the section 28 principle).

However, the AER's definition will not necessarily capture it. This is because it is not an above or below standard service (for the purpose of the first two bullet points), and it may not necessarily be a dedicated asset (for the purpose of the 3rd bullet point – in this regard see discussion on connections above).

Public Lighting

EnergyAustralia's proposal also allowed for negotiated services arrangements to apply to public lighting services. The range of negotiable components of direct control services which EnergyAustralia proposed would also apply in many cases to public lighting customers.

It is not clear how public lighting is to be treated under the AER's proposed definition. The restricted definition of negotiable services that the AER has applied to direct control services could not in practical terms be applied to public lighting customers. The AER is requested to clarify what, if any, negotiable components it proposes for alternative control services.

3.2 Inconsistencies with MCE's policy intent

MCE never intended a codified set of arrangements with transmission

During the course of development of the Transitional Rules and Distribution Rules, EnergyAustralia and other DNSPs made strong submissions to establish that the transmission negotiated service definition should not apply to distribution. This argument was accepted by policy makers in the development of Transitional Rules.

The MCE decided not to adopt the transmission regime for the NSW/ACT Transitional Rules[274] If the MCE had wanted the same negotiated service arrangements for distribution as apply to transmission, it would have prescribed it in Rules.

In effect, the AER has reversed the MCE's decision by applying the transmission Rules to the definition of negotiable components of direct control services.

AER's definition goes well beyond what would be considered a "component" of a service

Rather than identifying particular components, the AER's proposed definition is in broad terms – particularly dot point three, which is capable of capturing or impacting upon just about every aspect of the "connection service", see the discussion of connection service above.

This is contrary to the intent of Part DA in requiring only particular "components" (rather than whole services) to be so classified.

[274] See MCE/SCO Explanatory Material "Changes to the National Electricity Rules to establish a national regulatory framework for economic regulation of electricity distribution April 2007" at p 42 which states that ACT/NSW Distributors do not have negotiated distribution services.

The Rules definition of "connection service" is not a "component", but an entire multi-layered service.

Despite this distinction between dedicated and shared, a network user does not experience distinct services, but rather one integrated service. Furthermore, prior to connection, there is a complex layering of services within services or conditions of service, but the user experiences one seamless service on connection.

3.3 Inconsistencies with other aspects of the regulatory framework

As noted above, the third limb of the AER's definition is extremely broad and capable of capturing or impacting upon just about every aspect of the "connection service".

Some of the aspects of the connection service in the bullet point list above are "monopoly services" – for example, the DNSP preparing a design brief for new assets to be constructed, and subsequent certification of that design.

Monopoly services have historically been separately regulated by IPART, in the form of fixed rates and charges, and the AER proposes to continue that form of regulation[275]. In clause H.2(b) of Appendix H of the AER's draft determination, the AER states that:

> Unless otherwise specified, the charge that is to be levied by a DNSP for the provision of a monopoly service described in section H.4, must not be more than or less than the charge specified or calculated for that monopoly service in that section.

If such services were to be classified as negotiable components of direct control services, Part DA would apply, which suggests that the price might be up for negotiation in certain circumstances. This would appear to be inconsistent with the AER's intent with respect to monopoly services. This in turn causes EnergyAustralia to wonder whether the AER has considered the breadth of its proposed third bullet point and its practical implications.

EnergyAustralia has concerns that the rates and charges specified for monopoly services by the AER in its draft determination are too low and not sufficiently cost-reflective. From that perspective, EnergyAustralia would be open to having the ability to negotiate increased charges in order to be more cost-reflective. However, this does not appear to be consistent with the AER's intent.

The only aspect that it would clearly not capture is the design and construction of new capital works funded by the user. This is because these fall within the definition of "Customer Funded Connections"[276] under IPART's 2004 network determination[277], which IPART classified as "excluded services". Consequently, they are not direct control services in the first place, for the purposes of the AER's third bullet point – either because they are "unregulated", under clause 6.2.3B(2)(i) of the Transitional Rules and the AER's draft determination, or (if the AER accepts EnergyAustralia's submission on classification) "unclassified".

Capital Contributions Determination

Some of the aspects of the connection service in the bullet point list are regulated by IPART's Capital Contributions Determination – for example, decisions regarding which of the new capital works (to be constructed to accommodate the connection) are to be funded by the user and which by the DNSP.

IPART's Capital Contributions Determination, which continues to apply during the 2009 – 2014 regulatory period by virtue of clause 6.21.4 of the Transitional Rules, sets out detailed principles which must be applied in this situation.

In broad terms, IPART's Capital Contributions Determination makes a distinction between "dedicated" and "shared" assets – a distinction that is similar to (although not quite the same as)

[275] However, it would appear that this form of regulation will now apply to generators as well as to customers. Clause 3.1 of IPART's 2004 network determination stated that a DNSP may only charge the relevant Prescribed Distribution Service Charges (for Prescribed Distribution Services including Monopoly Services) to "Distribution Customers". The definition of this term did not extend to generators. However, there is no equivalent provision in the AER's draft determination

[276] This includes works funded by either customers or generators, and whether they are dedicated or shared.

[277] IPART's Final Determination No 2, 2004 (relating to NSW Electricity Distribution Pricing 2004/2005 to 2008/2009).

other terminology in the Rules[278]. In general, the customer is responsible for procuring and funding dedicated assets, and the DNSP is responsible for procuring and funding shared assets. However, there are some exceptions – for example, the DNSP is responsible for procuring and funding "excluded connection works", and certain rural and large load customers are responsible for procuring and funding network augmentations.[279]

The effect of IPART's Capital Contributions Determination is that, in the great majority of instances, the customer is responsible for meeting the whole cost of those assets which are dedicated to the supply of that single customer. The capital expenditure forecasts which form part of EnergyAustralia's regulatory proposal have been based on the continuation of these arrangements. Connection assets which are provided in accordance with the Capital Contributions Determination provide direct control services to the customers concerned. Upon completion, the assets become indistinguishable from others which form the DNSP's distribution system, albeit their value is not recognised as part of the Regulated Asset Base.

Nothing in Part DA should alter or cast doubt on these principles. For example, if the Capital Contributions Determination requires a customer to fund dedicated connection works, and the customer wants works falling into that category built, then nothing should suggest that there can be any negotiation over the principle of whether the customer should fund them.

This is of course distinct from discussions over how the Capital Contributions Determination might apply to any particular scenario. In this regard, Schedule 3 of that determination sets out a dispute resolution regime to cover this.

Decisions as to who funds which assets (dedicated, shared etc) should be made on the basis of clear regulatory principle, with negotiations reserved for the application of those principles in any particular case (rather than around the principles themselves).

Conclusion

EnergyAustralia asks the AER to reconsider our proposal in respect of negotiable components of standard control services. We believe our approach is simple, flexible and adaptive to the needs of our customers and the services we provide them.

This chapter highlights the ambiguity inherent in the AER's draft determination that, should the AER not move from its draft, would need to be addressed.

EnergyAustralia also notes that the AER considers its approach is a simple one that allows a transition to alternative arrangements once negotiable components cease at the end of the next regulatory control period. At this time, those services will either have to be reclassified as negotiated services or will remain as direct control services not subject to negotiation.

EnergyAustralia does not consider that the issues raised in this submission on this aspect are relevant only to the 2009-2014 regulatory period. Rather, they have ongoing relevance and EnergyAustralia intends to make further submissions on the Rules in relation to these aspects at a later date. Recognition of some of these issues in the Transitional Rules is in this respect a first step, rather than a last step.

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[278] The actual terminology used is not quite so simple- it uses the concept of "linkage point" where assets change from dedicated to shared. Therefore it may be possible for assets upstream of the linkage point to be effectively "dedicated" (ie initially dedicated, but with potential for sharing in the future) but for those assets to be classed as network augmentations.

[279] In practice there can be issues with implementing this, as allowing an ASP to work on the shared network is not always practicable from the point of view of network security and safety.

4-5. Control mechanisms for standard control services

REVISED PROPOSAL

EnergyAustralia has revised its June 2008 proposal in respect of the control mechanism that is to apply to its standard control (DUoS) services and the X-factors that will apply. The revision (a proposal to introduce a G factor to the price cap) responds to matters raised by the AER in respect of other decisions, notably the pass through of costs related to the introduction of an emissions trading scheme and to respond to the AER's request for EnergyAustralia to provide revised energy forecasts.

EnergyAustralia has also accepted the AER's draft decision to retain the double sigma representation of the weighted average price cap formula.

Excepting the proposal of the G factor, and the double sigma representation of the price cap, EnergyAustralia has not revised its proposed application of the control mechanism. EnergyAustralia notes in this chapter the reasons why not all the matters raised by the AER require a change to what EnergyAustralia originally proposed.

In line with the above comments, EnergyAustralia has also revised Attachment 4.1 – EnergyAustralia's Calculation of the Weighted Average Price Cap. The modified Attachment is attached to this revised proposal as Attachment II.4A.

EnergyAustralia has not revised its proposed control mechanism for its Transmission Use of System Services. The AER's draft determination largely accepted EnergyAustralia's June 2008 proposal.

This chapter, together with chapters 4 and 5 of the June 2008 proposal and Attachment II.4A to IIA.E now comprise EnergyAustralia's current proposal in relation to the control mechanisms (DUOS and TUOS services). Attachment II.4A replaces Attachment 4.1 to the June 2008 proposal.

Attachments II.4E1 replaces Attachment 13.1.

Rule requirements

The AER's distribution determination is predicated on a decision on the control mechanism (including the X factor) for Standard Control Services (Clause 6.12.1(11)).

The control mechanism for standard control services (excluding transmission) must be substantially the same as that determined by IPART in 2004 (Clause 6.2.5(c1)(1).

The control mechanism for standard control (transmission) services must be substantially the same as that determined by the ACCC in 2004 (Clause 6.2.5(c1)(3).

Positive and negative change events and the associated pass through provisions relate to increased or reduced costs (ie. not to changes in consumption volumes and the associated revenues) (clause 6.6).

Our June 2008 proposal

EnergyAustralia's Service Classification and Control Mechanism Proposal (Part II, chapters 4 and 5) demonstrated our proposed approach to establishing the control mechanism to each separate category of DUoS services.

EnergyAustralia noted that its proposal complied substantially with the AER's guidelines for the control mechanism for standard control services with the following minor exceptions:

- freedom to vary miscellaneous fees and monopoly charges with the same constraints that apply to standard network tariffs.
- adjustments to the X-factors to account for D-Factor and other incentive mechanisms. This is to ensure that recovery of these incentives is not limited by tariff side constraints.
- a small simplification to the mathematical representation of the price cap to use a single summation, rather than the current double summation, which provides an identical outcome.

EnergyAustralia also proposed to maintain the audit requirements of WAPC and TUoS quantities for DUoS pricing. We also proposed the continuation of IPART's approach to reasonable estimates to account for tariff transfers and restructuring.

AER's draft determination

In its draft determination, the AER:

4-5. Control mechanisms for standard control services
(continued)

- proposed that the WAPC form of price control be implemented for the 2009-14 determination;
- made a minor change to the formulation of the WAPC, in that it proposed that the adjustments to the form of price control would be multiplicative, rather than additive;
- did not accept EnergyAustralia's proposal of a minor change to the WAPC to treat miscellaneous and monopoly charges in the same manner as network tariffs;
- did not accept EnergyAustralia's proposal of a minor change to the formulation of the WAPC to facilitate the assessment of compliance with tariff side constraints;
- accepted EnergyAustralia's proposal to continue with IPART's reasonable estimate provisions; and
- did not agree to EnergyAustralia's proposed minor change to the mathematical formulation of the WAPC.

Our response to the AER's draft determination

EnergyAustralia has revised its regulatory proposal in respect of its proposed control mechanism for standard (DUoS):

- Section 4.1 sets out EnergyAustralia's revised control mechanism, to address matters raised by the AER's draft determination in respect of energy forecasts, whilst ensuring the control mechanism can meet the Revenue and Pricing Principles in the NEL.
- Section 4.2 sets out EnergyAustralia's reasons why EnergyAustralia does not support the AER's decision to reject our proposed approach to the treatment of miscellaneous fees and monopoly charges.
- Section 4.3 sets out EnergyAustralia's response to the AER's rejection of EnergyAustralia's other proposed minor changes to the WAPC formula.

4.1 Revising the control mechanism to account for uncertainty in growth forecasts

EnergyAustralia's revised building block proposal (part 1 chapter 13) notes that the AER's request to incorporate up to date data in a revised energy forecast should also take account of other economic factors including government policy initiatives that will impact energy prices and have a consequent impact on energy sales.

EnergyAustralia has considered the impact of the following factors in its revised energy (and peak demand) forecast and X-factors:

- the introduction of the CPRS (Carbon Pollution Reduction Scheme);
- updated economic growth forecasts;
- draft outcomes of network price increases (taken from the AER's draft determination);
- outcomes of IPART's retail price determination; and
- government initiatives relating to coal royalties and distribution levies.

Reflection of updated information on CPRS in energy forecasts

EnergyAustralia noted in its June proposal that it had not included in its energy forecasts any future impact of the Carbon Pollution Reduction Scheme (CPRS) because, at the time of submission, insufficient details of the proposed scheme were available to assess its impact.

The AER's consultant, MMA, with the benefit of more up to date information, raised this issue in its final report in respect of demand and energy forecasts. This included analysis of the likely impact of such a scheme on forecast energy growth.

While the AER's draft determination notes that the MMA analysis is sound, it made no explicit recommendations to account for CPRS in energy forecasts over the period. However, the AER, in its draft determination, stated that EnergyAustralia's forecast should be updated to take into account the most recent data in February 2009.[280]

The Garnaut Report was released in July 2008. Commonwealth Treasury modelling, and the Government's White Paper published in December 2008 indicate that a CPRS

[280] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p116-117.

will significantly increase electricity prices and lead to reduced energy consumption.

Chapter 13 of our revised building block proposal notes that the CPRS is designed to change household and business consumption patterns away from carbon intensive products. As the price of electricity rises, it is likely that businesses will look for more cost effective production processes and households will look to reduce their discretionary consumption of electricity (eg. decide not to use air-conditioners on mild days). The extent of this response to higher prices is dependent on the price elasticity of demand.[281]

Uncertainty associated with CPRS impacts

It should be noted that the impact of the CPRS is not known with certainty and that EnergyAustralia's forecasts of energy rely on published information about the effects of the CPRS on energy prices and customers' sensitivity to those changes in price.

NSW DNSPs are facing a quite unprecedented level of uncertainty, during the 2009-14 regulatory control period, in both:

- energy consumption forecasts from which their revenues will be derived; and
- their business costs.

However, current regulatory arrangements are asymmetric in that they provide no relief for volume impacts, but would allow relief by way of a pass through for the cost impacts of CPRS.

As the AER has correctly acknowledged, the cost impact could be addressed as a regulatory change event under clause 6.6 of the Rules. However, the much more significant change to volumes and the associated revenue outcomes cannot.

[281] In this context, demand is being used as a term by economists to describe energy consumption. This needs to be distinguished from the term used by electrical engineers to describe the instantaneous consumption of power.

Pass through arrangements provide little relief for volatility in volumes caused by the introduction of the CPRS

The pass through arrangements in clause 6.6 of the Rules relate to increases and decreases in costs and accordingly do not enable the AER to make adjustments to the distribution determination to accommodate the variation in revenues caused by volume volatility.

In the absence of a considerable reduction to forecast volumes (to allow for a greater range of outcomes for energy growth from CPRS), or a change to the control mechanisms, EnergyAustralia is at risk of not having the opportunity to recover at least its efficient costs.

EnergyAustralia's proposed approach

Chapter 13 notes EnergyAustralia's assumptions on the impact of CPRS on forecast energy volumes. This still places us at considerable risk of not having the opportunity to recover our efficient costs should volumes fall below forecast levels. Should consumption not fall as much as predicted customers are at risk of paying higher prices based on lower forecast volumes that never eventuate.

This is because the WAPC control mechanism assumes that actual volumes will closely match forecast volumes, to deliver required revenues to cover costs. Where actual volumes do not match forecasts, revenue outcomes could be lower (or higher) depending on their relationship to the forecast.

EnergyAustralia's proposed G factor arrangements

To manage the unprecedented volume risk resulting from the CPRS, EnergyAustralia proposes a minor variation to the WAPC formula, to limit the extent to which revenues through network prices may vary from those targeted by the AER throughout the 2009-14 determination.

A G factor adjustment to the WAPC formula is proposed. This factor is not designed to interfere in any way with the intended operation of the WAPC, but would act in the following way to mitigate the risk that actual volumes may diverge widely from forecast quantities:

- The *G* factor would not act to adjust network prices if cumulative network revenues remain within *L*% of the lagged target based on efficient costs, as determined by the AER;

- In the event that cumulative revenues were to exceed target by more than *L%,* the *G* factor would act to reduce revenue to within *L%* of the target; and
- If cumulative revenues were to fall short of target costs by more than *L%,* the *G* factor would act to increase revenue to within *L%* of the target.

The G factor mechanism is designed to limit excursions above or below the intended target revenue trajectory to within acceptable bounds. The DNSP is still subject to potential gains and losses, consistent with the intention of a price cap. However, those gains or losses are kept within the boundaries proposed by the AER. Gains or losses up to the point where the G factor operates are still retained, and persist to the extent the DNSPs forecast is not brought back to the midpoint, but L% above or below the midpoint.

Proposed G Factor arrangement will result in substantially the same control mechanism

The proposed G Factor is still substantially the same control mechanism as that applied by IPART in its determination with respect to the 2004-2009 regulatory control period, as required by clause 6.2.5 of the Transitional Rules. The weighting mechanism for tariff components that applies under the WAPC is not altered.

"Substantially the same" essentially requires that the control mechanism has the same essence. It does not have to be identical, and can even differ in a respect that is material (in the sense of not trivial or inconsequential).

The requirement that the control mechanism has the same essence as that previously applied by IPART is clearly fulfilled. The control mechanism is still a weighted average price cap, rather than a revenue cap or hybrid mechanism. The constraint on prices under this cap continues to be set based on established X-factors, together with other adjustments. These features are the "essence" of the mechanism. In addition to this, if outturn energy volumes are not materially different from forecasts, the control mechanism will be no different from that which applies to EnergyAustralia in the current period and no adjustment due to the presence of the G factor would take place.

In effect, the G factor:

- mitigates against customers and EnergyAustralia from being penalised (on the one hand, in terms of higher prices and on the other, by lower revenues) because of inaccuracies in energy forecasts resulting from uncertain CPRS impacts; and
- normalises any inherent uncertainty in forecasts so that the control mechanism can apply in the same way it did in the 2004-09 period.

The existing control mechanism did not have to cope with the unforseen forecasting risk of a CPRS. The relative price changes faced by consumers over the last 5 and even 10 years have been mild. In comparison, the magnitude of the price increase from the CPRS (and its timing) is unparalleled. As a result the task of assessing future electricity use is also unparalleled. While models that project the impact of the CPRS exist, they rely on many assumptions and are therefore inherently uncertain. The G factor adjustment is a mechanism to deal with this uncertainty, while retaining a control mechanism that is substantially the same as applied by IPART.

This minor revision to the control mechanism, its rationale and further information on how the growth related co-efficient would apply are set out in Attachment II.4B. A hypothetical example is used to illustrate the concept,

4.2 Treatment of Miscellaneous Fees and Monopoly Charges

The AER rejected EnergyAustralia's proposal to include Miscellaneous Fees and Monopoly Charges under the WAPC in the same manner as the tariffs for standard control (DUoS) services[282]. EnergyAustralia's proposal was designed to allow limited freedom to vary those fees and charges.

The AER's decision to reject EnergyAustralia's proposal appears to be on the basis of it having insufficient time to consider the matter properly. The AER also argued that the costs of these services are already factored into the building

[282] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p 53

block proposal, so (presumably) our concern for cost recovery is already covered. In this, the AER has either misunderstood or misrepresented EnergyAustralia's motives in formulating its proposal.

The AER has not made provision for Miscellaneous Fees and Monopoly Charges to be set at levels that recover their efficient costs

Whilst the control mechanism must be substantially the same as that applied by IPART in its determination with respect to the 2004-2009 regulatory control period[283], the AER may still exercise its discretion in relation to the exact form of the control mechanism. Consequently, when determining the application of the control mechanism to Miscellaneous Fees and Monopoly Services, the AER is exercising its discretion in relation to making (part of) a distribution determination relating to direct control services. Consequently, section 16 of the NEL requires the AER to take the revenue and pricing principles set out in section Section 7A of the NEL into account, when exercising its discretion.

The AER has not expressly addressed the application of the revenue and pricing principles in its decision on the control mechanism for direct control services. In particular it has not explained how the Schedule of Fees and Charges set out in Appendix H of the AER's draft determination will provide EnergyAustralia (or other NSW DNSPs) with a reasonable opportunity to recover at least the efficient costs of providing those services. In 2007/08 the approximate revenue for Miscellaneous Fees and Monopoly Charges was $8.7 million (excluding emergency recoverable works).

EnergyAustralia has estimated the costs of providing the same number of services in 2009/10 at $18.4 million.

The AER's draft decision, in which it replicated IPART's 2004 decision to escalate the fees and charges by cumulative CPI, would only enable EnergyAustralia to recover of $10.5 million in 2009/10 for the same volume of services. That is, Miscellaneous Fees and Monopoly Charges would only recover some 57% of costs[284].

The AER, in acknowledging real cost increases over the period but no real price increases for monopoly fees over the same period is effectively increasing the cross subsidy between these charges and other DUOS charges.

The significant discrepancy between the cost of these services and the associated charges to customers is not consistent with the pricing principles set out in the NEL, specifically the principles at sections 7A(2)(a) or 7A(3)(b), and will not provide EnergyAustralia with either:

- a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services; or
- effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides.

With respect to the latter point, services that are provided at around half of their actual cost must inevitably lead to inefficient overuse by customers.

The AER has not considered the benefits of allowing more flexibility in pricing arrangements which would remove inherent cross subsidisation that still exists for these services

It is not clear from the draft determination whether the AER has properly considered the material provided in support of EnergyAustralia's proposed approach and rejected it, or simply failed to consider it. That the AER has deferred consideration of the matters until the 2014-2019 regulatory control period due to "truncated time lines"[285] does not recognise their importance. To the extent that the AER has not considered this part of EnergyAustralia's proposal it is in error. The AER is required to take into account all material relevant to its decision. It is

[283] Clause 6.2.5 of the Transitional Rules.

[284] See Attachment II.4C: *Miscellaneous Fees and Monopoly Charges – Comparison of Revenue Outcomes when applying EA v AER proposed rates*, January 2009.

[285] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p 53.

4-5. Control mechanisms for standard control services

(continued)

unreasonable to defer the proper consideration of issues which arise due to truncated timelines. In addition, there is no reasonable basis for the AER rejecting EnergyAustralia's proposed minor change to the formulation of the WAPC to permit the inclusion of miscellaneous fees and monopoly charges in the same manner as the tariffs for network service.

Most importantly, the AER has failed to consider the importance of charging economically efficient prices for services, which the flexibility of EnergyAustralia's proposal was intended to allow. That is, prices should reflect efficient costs, to ensure that there is neither inappropriately high demand for low priced services nor artificially low demand for high priced services.

EnergyAustralia's approach would also have a significant advantage in enabling the creation of new fees or charges and permitting their variation during the course of the determination to reflect the costs incurred, which the approach proposed by the AER does not allow. As with the implementation of new tariffs, this would be subject to the Regulator's approval.

The costs of providing miscellaneous and monopoly services vary over time, so EnergyAustralia should have the freedom to appropriately reflect that in pricing. The efficient pricing of services will deliver efficient use of that service. We should be allowed to set prices for these services that balance these with all the other service costs of our business.

EnergyAustralia's proposal to allow Miscellaneous Fees and Monopoly Charges (M&Ms) to vary like other DUoS rates does generate additional revenue. With the X-Factors set at the beginning of the regulatory period, forecast M&M revenue will already be accounted for in those X-factors. The real purpose in allowing freedom to vary M&M prices is to target efficient pricing of these services. The service will be subject to exactly the same level of scrutiny and control that the AER would exercise over DUoS prices.

This element of EnergyAustralia's proposal does not alter the revenue that EnergyAustralia would receive by providing these services. Indeed, it would act to simplify the operation of the WAPC by treating all revenue elements equally, rather than by separately accounting for the Miscellaneous Fees and Monopoly Charges as an adjustment to the WAPC. Under the current regulatory arrangements, the revenue associated with Miscellaneous Fees and Monopoly Charges is considered as a separate subset of the revenue permissible under the operation of the WAPC.

The AER in effect proposes to continue with the unsatisfactory approach adopted by IPART and is urged to reconsider the advantages of EnergyAustralia's proposal. It should be noted that the current arrangement was adopted by IPART as a work-around to the price control mechanism of its final 2004 determination for legal reasons. IPART originally intended to include Miscellaneous Fees and Monopoly Charges under the WAPC, with their price contribution calculated in the same manner as network tariffs. This is the approach which EnergyAustralia is advocating.

However, IPART then superimposed an additional control to prevent the movement of these fees and charges during the course of the determination. EnergyAustralia firmly believes that there is no need for this additional control, which is perpetuating inefficient charges for services which the very formulation of the WAPC is designed to facilitate.

EnergyAustralia has provided an updated assessment of the costs in providing miscellaneous and monopoly services in Attachment II.4E. Applying the Control Mechanism to Miscellaneous and Monopoly Services, and this attachment should be read in substitution of Attachment 13.1 to the June 2008 proposal.

4.3 Rejection of other minor amendments to the control mechanism

The AER rejected EnergyAustralia's proposed adjustment to the control mechanism to account for D-Factor and other incentive mechanisms, on the basis that the Rules already allow for these types of adjustments to be excluded when applying side constraints.

EnergyAustralia had proposed that the D-Factor and other adjustments be taken into account in the CPI-X formula as a $CPI\text{-}X_{ADJ}$ term, which could then also be applied to the price limit formula.

Part II – Services classification and control mechanism proposal

EnergyAustralia's comments

EnergyAustralia does not agree with the AER's interpretation of 6.18.6

The AER believes that the Rules allow a modification to the prices to exclude D-factor and other incentives without affecting the side constraint provisions[286]. EnergyAustralia is very concerned that the Transitional Rules do not actually support such an interpretation, even if it was the intention of the rule makers. For this reason, EnergyAustralia has proposed a minor change to the control mechanism itself to achieve the intended effect in a much simpler fashion[287,288]

Clause 6.18.6 of the Rules allows for exclusion of items that are *variations to a distribution determination* when assessing compliance with tariff side constraints. Despite the cross-reference to rules 6.6 and 6.13 in clause 6.18.6, some incentive mechanisms like the D-Factor modify the control mechanism. They do not technically vary the distribution determination like cost pass throughs. In clause 6.6 of the Rules, pass through items, the STPIS incentive and the D-Factor are not described as *variations* but instead termed *Adjustments after making of building block determination*.

D-Factor incentive arrangements and other incentives that are linked to the control mechanism are not revenue adjustments. Arguably, they have the potential to be included within tariff side constraints unless the control mechanism is more explicit about how these items are to be treated.

As a result, the incentives established under the Rules may be diminished by the inflexibility of robustly applying legacy control mechanism formulae. For example, it might be possible to be entitled to receive $15 milion in incentives, but not be able to collect some or all of this because side constraints limit the recovery of that amount.

[286] AER Draft Distribution Determination p 48.
[287] EnergyAustralia Regulatory Proposal, June 2008, p 183.
[288] We further explained this proposed minor change in EnergyAustralia's letter to the AER of 1 August 2008, p4, which is included as part of this revised proposal for completeness as Attachment II.4D: L20080801 Response to D Factor and WAPC questions FINAL

The application of the price cap and side constraint formula is problematic

The AER has not provided sufficient detail of its proposal for EnergyAustralia to fully understand the implications for the price setting process. However it is apparent that the AER has failed to consider that its proposal separates the application of the price cap and side constraint formulae. This factor alone would impose a very significant additional degree of complexity in both administration and compliance during the course of the determination.

The annual price setting process would involve the production and compliance assessment of two complete sets of DUoS prices:

- The first, which would be those applied to customers, for compliance with the WAPC; and
- A second set, excluding any pass through, EBSS and D-Factor components, for compliance with the side constraint.

For example, consider that a DUoS price is calculated for a domestic tariff at say 6.0 ¢/kWh. This price complies with the Weighted Average Price Cap (WAPC) control mechanism. Under the AER's proposed approach, this price includes the recovery of costs for D-Factor and other incentives. But side constraint compliance requires the calculation of another DUoS figure which excludes the D-Factor and other incentives. By way of illustration, if the D-Factor were 0.1 ¢ /kWh, then:

- $DUoS_{WAPC\ COMPLIANCE}$ = 6.0 ¢/kWh; and
- $DUoS_{SIDE\ CONSTRAINT}$ = 5.9 ¢kWh

As can be seen, two sets of DUoS prices will be required to be submitted. Also, because the side constraint formula compares new prices with the preceding year's prices, the $DUoS_{SIDE\ CONSTRAINT}$ prices will have to be maintained independently from the $DUoS_{WAPC\ COMPLIANCE}$ prices for the duration of the regulatory period.

Note therefore that D-factor recovery effectively becomes another sub-component within each tariff. Must the D-factor be recovered on an equal percentage basis across all tariffs? What discretion does the DNSP have in this regard? Guidance is sought from the AER in this respect if EnergyAustralia's proposed approach using X_{ADJ} is not adopted.

4-5. Control mechanisms for standard control services

(continued)

Consider that during the regulatory period there may be a need to increase say a domestic $DUoS_{WAPC\_COMPLIANCE}$ price to the limit to reflect changing costs, in which case the $DUoS_{SIDE\_CONSTRAINT}$ price may be exactly the same (i.e. the 0.1 ¢/kWh mentioned above for D-Factor recovery would in fact be 0.0 ¢/kWh for some tariffs to allow the price to achieve its maximum increase under the side constraints.)

To achieve this, other tariffs will need to recover disproportionately more of D-Factor incentive costs, say 0.2 ¢/kWh or more, rather than 0.1 ¢/kWh.

This additional complexity and potentially uneven recovery of incentive costs arises because two sets of DUoS prices will be required to be submitted.

In contrast, EnergyAustralia's proposal, involving modification of the X factor to adjust for incentive amounts would achieve the same compliance outcome, whilst only requiring the formulation of a single set of prices. This is in fact the process which has been established by IPART for treatment of D-factor amounts in the current determination.

EnergyAustralia therefore requests the AER to reconsider its proposed complex "dual tariff" application of the WAPC and side constraint provisions.

We note that Clause 6.12.1 of the Transitional Rules requires a decision on how compliance with a control mechanism is to be demonstrated. If the AER does not reconsider its proposed requirement for assessing compliance with the WAPC and the side constraint, EnergyAustralia requests that the AER must provide a sufficiently detailed explanation of its approach to managing compliance through two sets of DUoS prices to enable its decision to be properly administered during the regulatory control period.

The AER has allowed provision for reasonable estimates

In its June 2008 regulatory proposal, EnergyAustralia proposed to continue with IPART's established arrangements for "reasonable estimates", to be applied to situations where customers transfer between tariffs or take up new tariffs.[289]

EnergyAustralia is pleased that the AER has decided to continue with this arrangement. This allows for the creation of new tariffs or tariff components which do not have historic volumes to weight against in the price cap formula. It also provides for transfers between differently priced tariffs, where because of the transfer a DNSP stands to either gain or lose revenue.

Summary of recommendations

EnergyAustralia is disappointed that the AER did not accept its proposal of a minor change to the formulation of the WAPC to permit the inclusion of miscellaneous fees and monopoly charges in the same manner as the tariffs for network service.

This approach is believed to have a significant advantage in enabling the creation of new fees or charges and permitting their variation to reflect the costs incurred, which the approach proposed by the AER does not allow. The AER proposes in effect to continue with the unsatisfactory approach adopted by IPART and is urged to reconsider the advantages of EnergyAustralia's proposal.

There have been very significant developments in the implementation of a CPRS which have taken place since the submission of EnergyAustralia's proposal. This has introduced an unprecedented level of uncertainty in the formulation of volume forecasts. Accordingly, a minor variation to the WAPC formula is proposed, to limit the extent to which revenues through network prices may vary from those targeted by the AER throughout the 2009-14 determination. A *G* factor adjustment to the WAPC formula is proposed. This would act in the following way:

- It would not act to adjust network prices if cumulative network revenues remain within *L*% of the lagged target based on efficient costs, as determined by the AER;
- In the event that cumulative revenues were to exceed target by more than *L*%, the *G* factor would act to reduce revenue to within *L*% of the target; and

[289] EnergyAustralia, June 2008 regulatory proposal, p181.

- If cumulative revenues were to fall short of target costs by more than L%, the G factor would act to increase revenue to within L% of the target.

6. Division of revenue

The June 2008 proposal included a separate chapter on the Division of Revenue between transmission and distribution. EnergyAustralia's comments on the Division of Revenue draft decision are contained in the Annual Revenue Requirement chapter of this revised proposal (see Chapter 1 of Part I)

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7. Control mechanism for alternative control services

SUBMISSION

EnergyAustralia has not revised its June 2008 proposal for the control mechanism to apply to alternative control services (the construction and maintenance of public lighting) on the basis that the AER has not provided a rule compliant draft determination. However, EnergyAustralia has responded to the way the AER intends to make its decision and has provided further information that the AER should take into account when making its draft decision. The additional information relates to:

- the impact of actual CPI for 2007/08 and the changes made to labour escalators;
- change to the pricing methodology for Rate 4 tariffs; and
- the impact on prices from the assumption that the economic life for public lighting supports is 35 years (rather than 20 years).

Chapter 7 of Part II of the June 2008 proposal, including attachments 7.1 and 7.2, remains EnergyAustralia's current proposal in relation to the control mechanism to apply to public lighting. This chapter should be considered together with EnergyAustralia's current proposal.

Rule requirements

A draft distribution determination is predicated on a decision by the AER on the control mechanism for alternative control services in accordance with Transitional clause 6.12.1(12). It is also required to make a decision on how compliance with that control mechanism is to be demonstrated under Transitional clause 6.12.1(13).

Clause 6.2.5(a) states that a distribution determination is to impose controls over the prices and/or revenue derived from direct control services. Clause 6.2.5(c2) requires the control mechanism for alternative control services to consist of:

(1) a schedule of fixed prices

(2) caps on the prices of individual services

(3) caps on the revenue to be derived from a particular combination of services

(4) tariff basket price control

(5) revenue yield control

(6) a combination of any of the above

In deciding on the control mechanism the AER must consider:

(1) the potential for the development of competition in the market and how the control mechanism might impact that potential

(2) the administrative costs

(3) the regulatory arrangements in the 2004-09 regulatory period

(4) the desirability for consistency of regulatory arrangements (including across jurisdictions)

(5) any other relevant factor

The basis of this control mechanism must be stated in a distribution determination (transitional clause 6.2.6(b)).

Our June 2008 proposal

EnergyAustralia proposed a single schedule of fixed prices for each public lighting component type. This was based on the annual capital and maintenance cost to install and to maintain each public lighting component. This form of control mechanism is the same as that used by IPART for the 2004-09 regulatory control period.

The average price increase proposed for the first year of the new regulatory period was 28.7% in order to achieve cost reflective prices. However, with the rebate proposed by EnergyAustralia, the price increase was reduced to only 10.8%. Over five years customers would on average experience a 38.7% increase (excluding CPI).

AER's draft determination

The AER did not accept EnergyAustralia's proposed schedule of prices for alternative control services. The AER did not propose an alternative schedule of prices, instead it proposed a general approach to determine prices. The AER:

- Rejected the use of replacement cost to value existing assets

7. Control mechanism for alternative control services

(continued)

- Rejected the form of control mechanism - a single schedule of fixed prices
- Rejected the use of the annuity approach for assets constructed prior to 1 July 2009
- Proposed a new form of control mechanism, i.e. two schedule of fixed prices
- Proposed that the annuity approach should only be used to calculate prices for new assets
- Proposed the new prices for existing assets should be calculated using an asset base roll-forward

Our response to the AER's draft determination

EnergyAustralia does not consider that the AER has made a relevant decision regarding pricing for the construction and maintenance of public lighting for the purposes of the Rules as it has not made a decision as required by the Rules with regard to alternative control services.

EnergyAustralia considers that it submitted a compliant proposal that used an innovative method to calculate prices which addressed data limitation issues but delivered cost reflective prices whilst mitigating the immediate impact of higher prices to customers.

EnergyAustralia does not consider that the AER has proposed an alternate pricing mechanism that is as successful in eliminating cross subsidies between customers or that addresses data limitations.

EnergyAustralia's response to the AER's considerations has been structured as follows:

- Section 7.1 - Failure to make a valid determination
- Section 7.2 - EnergyAustralia's proposal and why it was appropriate
- Section 7.3 - AER's information request and the results
- Section 7.4 - Consideration of the AER's commentary
- Section 7.5 - Alternative options considered by EnergyAustralia.
- Section 7.6 - Response to technical and other issues.

7.1 Failure to make a valid determination under Rules

EnergyAustralia considers that the AER has failed to make a valid "constituent decision" under clause 6.12.1(12) of the Rules. The AER rejected EnergyAustralia's proposal, and having done so, is required as part of its draft determination to substitute its own control mechanism (that is a schedule of prices) in accordance with clause 6.12.3.

The AER has only partially completed its duty under the Rules in that it has indicated the form that the control mechanism will take by signalling its intention to set a schedule of prices and a method by which these prices should be calculated, but has not imposed a control mechanism per se. That is, it has not specified a mechanism that will actually impose controls on these prices. If the control mechanism is a schedule of fixed prices, the control on the price is the specified price (taken together with any subsequent price path, which then constitutes a cap on the prices).

As a consequence, the AER has not made a constituent decision or draft determination in relation to public lighting. To do so, the AER must either approve EnergyAustralia's proposed schedule of prices or decide on a substitute schedule.

EnergyAustralia requests that the AER make that decision and afford EnergyAustralia the opportunity to make submissions in response to that decision.

To assist in this decision making process, EnergyAustralia has responded to the AER's request that two price schedules be submitted. If the AER accepts the pricing information, it should formally proceed to make a draft determination with respect to the control mechanism for public lighting. EnergyAustralia would then have an opportunity to respond to that draft determination by way of submission or by revising its current proposal before the AER proceeds to a final determination.

This chapter should be read as a submission in the context of the AER's consideration of public lighting, and a response to the AER's information request rather than a revised proposal with respect to the control mechanism for the construction and maintenance of public lighting.

AER considerations

The AER has indicated its intention to apply a schedule of fixed prices in the first year of the regulatory control period as its primary form of control for alternative control services. The AER has also indicated that this form of control will incorporate two schedules of prices:

(i) a schedule of fixed prices in the first year of the next regulatory control period for assets constructed before 1 July 2009; and

(ii) a second schedule of fixed prices in the first year of the next regulatory control period for assets constructed after 30 June 2009.

The AER has also indicated that the price path for both price schedules will vary with CPI for the remaining years of the 2009-14 regulatory control period.

The AER modified its approach to that set out in its statement on the control mechanism for alternative control services and considers this is warranted because:

- current pricing schedules do not reflect the actual cost of providing public lighting services;
- the AER has reviewed data on the cost of constructing and maintaining various categories of luminaire and is concerned that the NSW DNSPs' construction and maintenance costs are not reflective of their current price schedules, nor is it possible to reconcile data on the disparity of construction and maintenance costs between the NSW DNSPs;
- each of the NSW DNSPs has an asset register of public lighting assets but do not have comprehensive records of the age and condition of these assets. It is therefore not clear that a half life modelling assumption is appropriate;
- the NSW DNSPs have a large stock of assets of considerable age that suggests that charges based on current replacement cost for those assets is not appropriate; and
- there is evidence that some customers are currently cross subsidising other customers.

The following section summarises EnergyAustralia's proposal, and discusses each of the matters raised by the AER.

7.2 EnergyAustralia's proposal

EnergyAustralia considers that its proposal was appropriate, it was consistent with IPART's method, it met the AER's requirements in their guidelines, and it addressed many of the limitations of the IPART approach. Importantly, EnergyAustralia's pricing method resulted in cost reflective prices. To smooth the transition between prices in this period and those proposed for the 2009-14 period, EnergyAustralia developed a transitional price path with a rebate mechanism to minimise bill impacts to customers, particularly early in the period.

EnergyAustralia does not consider the AER's reasons for rejecting the annuity method used to calculate prices for EnergyAustralia's June 2008 proposal to be appropriate or robust.

Rigorous analysis

The prices in EnergyAustralia's June 2008 proposal for public lighting were determined through rigorous analysis and review of the costs of providing public lighting services. A comprehensive review of component material costs was undertaken to ensure that the prices generated as a result of modelling reflected the latest material costs faced by EnergyAustralia.

EnergyAustralia reviewed its labour cost forecasts and aligned its labour forecast for public lighting services with expected labour cost changes used in its proposal for standard control services. This involved application of EGW labour cost escalators to the labour component of public lighting component prices.

EnergyAustralia is also confident that its construction and maintenance costs are reflective of the current needs of public lighting customers. The operating cost forecasts were based on historic data, and adjusted for inflation and escalations in real labour costs.

Overcoming data limitations

EnergyAustralia acknowledges that it does not have comprehensive records of the age and condition of its public lighting assets. As a result, EnergyAustralia selected an annuity method to calculate prices because it avoids the requirement to forecast asset ages. Instead, it calculates equal annual charges for each component over the life of the asset. In contrast, the RAB roll-forward preferred by AER requires estimations to be made in relation to the remaining lives of all assets, which is the task both EnergyAustralia and the AER have identified as being problematic.

Consistent with AER guidelines and previous IPART method

The AER required that the DNSPs present an asset valuation that is derived from the previous determination[290]. EnergyAustralia considers that the annuity method presented in the June 2008 proposal is consistent with, in fact derived from, the 2004-2009 IPART determination. Both the annuity method proposed by EnergyAustralia, and IPART's 2004 determination calculate an annual customer charge for each public lighting component. They both allocate operating costs to customers on the basis of lamp replacements and luminaire maintenance, and both calculate a capital charge per component based on a return on and return of capital. Furthermore, the materials cost in both methods are derived from replacement costs, rather than historic costs. In most respects, the two methods are similar.

EnergyAustralia calculated the return of and return on asset using the annuity method. This is in contrast to the approach used by IPART during the 2004-2009 period which calculated the return on assets from an asset base that was assumed to be always halfway though its useful life. The half life assumption created prices that included a margin of error as some assets would be older than half the standard life and others would be younger. On average IPART considered the half life assumption to be appropriate. The annuity method applied by EnergyAustralia avoids the use of a half life assumption and therefore removes this margin of error in prices of individual public lighting components.

EnergyAustralia approach proven against others

EnergyAustralia considers the annuity approach to deliver lowest prices to customers that are still cost reflective. In our June 2008 proposal, we compared the annuity approach and the asset base roll-forward approach[291]. To do this, EnergyAustralia developed a simple roll-forward model, where assumptions were made for asset age in the absence of detailed historical records about installed public lighting assets. The roll-forward approach yielded higher prices for customers than the annuity approach adopted.

The roll-forward approach gave a closing RAB of $139.2 million at 30 June 2009. A key assumption in the roll-forward analysis was that the remaining life of public lighting assets was 13.2 years at 30 June 2007, and that newly installed components had a useful life of 20 years.

Since the June 2008 proposal, EnergyAustralia has revised its public lighting RAB as a result of a more detailed analysis of remaining component lives. Our current RAB value for 30 June 2009 is $111.3 million.

Benefits of EnergyAustralia's approach

EnergyAustralia maintains that the annuity method is the best method available for achieving cost reflective prices, for both new and existing components.

In developing its proposal, EnergyAustralia noted the AER's preliminary position set out in its statement of approach that it would allow DNSPs to collect revenues through prices that are reflective of the costs of providing efficient public lighting services of a particular standard[292]. EnergyAustralia refined its pricing methodology in response to its stated approach, and selected the annuity method.

EnergyAustralia outlined the merits of the annuity approach in the June 2008 proposal and in subsequent submissions. In summary the benefits are:

(i) it provides a single price list for customers;

(ii) it allows a clear and efficient cost allocation to customers based on their own component selections;

(iii) it avoids the immediate need for a comprehensive record of component ages and conditions; and

[290] AER, Final Decision-Control mechanisms ACT and NSW, p16.

[291] Table 7.2 EnergyAustralia Regulatory Proposal June 2008

[292] Final Decision (Alternative Control Services), p11, NSW DNSPs

(iv) it avoids forecast capital and operating expenditure that would be needed for a RAB roll-forward. Forecasts of both capital and operating expenditures are problematic as it is the customers, not the DNSP that decides which components are installed.

EnergyAustralia considers the annuity method to be more accurate than a roll-forward method based on the half life assumption used in the 2004-2009 IPART Determination. This is because it fully encompasses time value of money concepts and avoids arbitrary selection of remaining life for installed assets, and avoids consequent estimations of the return required for installed assets.

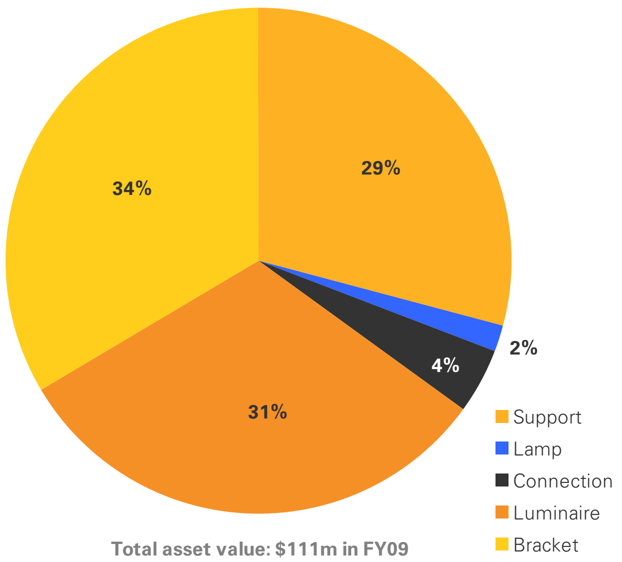
7.3 AER's information request and the results

In its draft determination document, the AER indicated its intention to reject EnergyAustralia's single price list approach The AER indicated it was concerned that the use of an annuity approach based on replacement cost as it would not reflect capital costs of assets at the time they were installed and therefore would over compensate service providers for public lighting services. The AER therefore requested that DNSPs provide two price lists, one based on a roll-forward model for assets that have been installed pre 1 July 2009, and one based on an annuity method for assets that will be installed post 1 July 2009.

EnergyAustralia has carried out analysis to determine how the AER's limited[293] RAB roll-forward for existing stock compares to the annuity approach adopted in our June 2008 proposal. The analysis was conducted using the following steps:

1. Calculation of a RAB for existing components of $111.3 million at June 2009. This RAB was allocated across all existing Rate 1[294] public lighting inventory as of December 2008. Assets that had installation dates that were more than 20 years old had multiples of 20 years subtracted from their age until the derived age was less than 20 years. The exception was supports which had a 35 year economic life assumed in this process as per the AER's requirement.

Figure 7.1 Spread of RAB across components



2. An estimate of the remaining lives of all components by customer was made using information from the public lighting database. In this analysis all components were assumed to have an economic life of 20 years, with the exception of lamps which have a technical life of 2.5 years and supports a technical life of 35 years.

   The average remaining lives for each component are as follows:

[293] 'Limited' in terms of the fact that the roll-forward approach is limited to setting prices for assets that have already been installed.

[294] Rate 1 in the EnergyAustralia public lighting database are assets that have both a capital and operating cost charge attributed to them:

Table 7.1 Average remaining lives

Component	Average Remaining Life (years)
Support	24.9
Connection	12.0
Lamp	1.4
Luminaire	12.7
Bracket	13.1

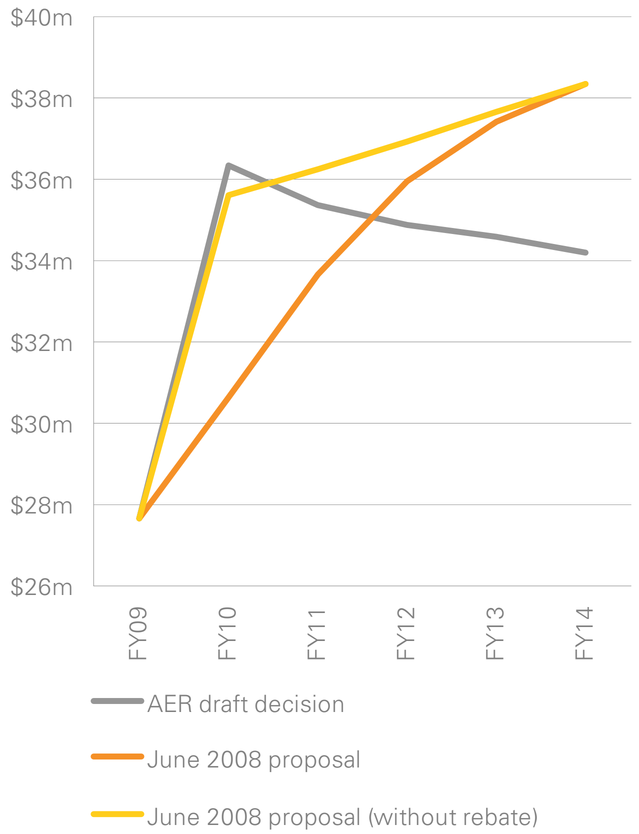
3. A RAB roll-forward was carried out for each component by customer. Component specific depreciation and return on assets (ROA) were calculated accordingly in order to generate a capital charge for each asset type.
4. An annual operating cost was allocated to lamps on the basis of spot and bulk replacement rates.
5. A revenue path for existing stock was calculated and the results were as follows:

The analysis shows that public lighting customers would be charged more for existing stock using the AER's limited RAB roll-forward. The first year average price increase under the RAB roll-forward method is 31.4%, compared to an average price increase of 28.7% derived using the annuity method proposed by EnergyAustralia in June 2008. With a rebate, the price change is only 10.8%.

In Figure 7.2 it can be seen that in 2011/12 the revenue for existing stock calculated by the AER proposed method falls below that calculated using the annuity approach. This is because the revenue for replacements was not included for the AER RAB roll-forward revenue path (as it applies to existing stock only). In the analysis some components have been depreciated to zero and not replaced due to a quarantine of existing stock. In reality EnergyAustralia would replace these fully depreciated items with new stock, and the revenue path would not decline.

The AER's concern that the annuity approach may lead to higher prices than a roll-forward approach appears unfounded. It should be noted that the roll-forward approach preferred by the AER can only be applied by making high level assumptions about asset age in the absence of detailed data. Not only does the method require these high level judgements, it results in higher prices for customers. For both these reasons, EnergyAustralia considers the roll-forward method to be inferior to the annuity method to calculate prices.

Figure 7.2 Price paths for different pricing methods



As mentioned earlier, EnergyAustralia proposed a rebate to customers to smooth the impact of bill increases. EnergyAustralia does not consider it to be feasible to include a rebate with the AER's roll-forward approach. This is because EnergyAustralia's rebate mechanism was applied to customers' bills rather than to individual prices. It is too complex to overlay a constraint that caps customer bill increases using two pricing systems (one for old assets and one for new assets). EnergyAustralia does not intend to provide a rebate mechanism if two prices lists are used for public lighting services.

7.4 AER's reasons

Asset age assumptions

EnergyAustralia considers that the inability to accurately determine the remaining lives of public lighting assets is a major limitation in applying the proposed RAB roll-forward for existing inventory. The AER has stated that DNSPs must estimate the remaining life for the assets related to each customer[295]. These estimates must be supported by documented analysis, and in the absence of detailed information, a default will be specified by the AER. Asset ages therefore become a crucial assumption for a RAB roll-forward, and yet the AER has not given any guidance on how these should be determined.

The AER has stated that EnergyAustralia has a large stock of assets of considerable age and suggests that charges based on current replacement costs for these assets is not appropriate. EnergyAustralia disagrees with this assertion.

EnergyAustralia considers the valuation of public lighting stock at its replacement cost provides a better benchmark for cost reflective pricing than would a historic cost valuation. This is because the *service* provided by EnergyAustralia is public lighting. EnergyAustralia does not provide public lighting assets per se. The public lighting assets are used to *provide* the service, and provided the assets are kept in good condition and replaced at the end of their useful lives, older assets should provide the same standard of service as newer public lighting assets. It is therefore appropriate that public lighting customers pay the same price for the same service regardless of whether that service is supplied by a relatively old asset or a relatively new one.

EnergyAustralia rejects the AER proposition that the public lighting asset base is comprised of a large number of assets that are near the end of their economic lives. Many of the public lighting assets within EnergyAustralia's franchise area were replaced at the time of the Sydney Olympics and therefore are relatively young. In any case, EnergyAustralia does not consider it practical to use individual historic costs in the pricing of the 1.3 million public lighting components currently installed.

EnergyAustralia considers that its annuity method that relies on replacement costs calculated every 5 years, at the start of a new regulatory pricing period, is a more practical method for determining prices. Furthermore, it ensures that the cost of existing services provided by existing assets keeps pace with the costs of new services that will be provided by new assets.

Benchmarking of costs

EnergyAustralia notes the AER's difficulties in reconciling construction and maintenance cost data between three different NSW DNSPs. However, we do not consider this is due to a lack of transparency, but rather due to the fact that different circumstances apply to the provision of public lighting services in each franchise area. Different organisational structures, different component offerings, individually negotiated supplier contracts and geographic considerations all impact the price at which public lighting services can be offered by a provider. It is therefore legitimate for costs to differ between service providers, even within the same jurisdiction. The presence of different prices is therefore not an indicator that a set of prices is inefficient, or inappropriate.

EnergyAustralia is aware of the difficulties associated with benchmarking prices of equipment, particularly where this involves sharing commercially sensitive supplier prices. EnergyAustralia has been pleased to contribute information to the AER but in doing so, remains committed to protecting the commerciality of its supply arrangements in order to protect the interests of public lighting customers in the future.

Cost reflective pricing – removes rebate, continue cross subsidisation

The AER notes that it is committed to providing cost reflective prices in the future, and acknowledges that cross subsidisation has been in place across public lighting customers based on prices set for the 2004-2009 period. Despite this admission and its statements regarding its desire to remove these cross subsidies, EnergyAustralia considers that the AER's intended approach will entrench cross subsidisation of customer prices

[295] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p339.

for the future. This is a very disappointing outcome for EnergyAustralia.

EnergyAustralia's annuity method was proposed in order to transparently derive cost reflective prices and remove existing cross subsidisations going forward. Our June 2008 proposal gave a price path that achieves cost reflectivity for all customers by 2014 and applied a rebate mechanism to ease the transition to cost reflective prices. EnergyAustralia considers the goal of cost reflective prices for all customers to be the fairest outcome. However, we note that the AER's preferred method of a limited roll forward for existing assets (based on historic costs) and an annuity approach (based on replacement cost) entrenches existing cross subsidies and reneges on commitments made by the AER to address this matter for all future periods.

We maintain that accurate price signals for customers are essential to ensure efficient investment in infrastructure and fair outcomes across the community. EnergyAustralia requests that the AER reconsider its approach on cross subsidisation and remove any non-transparent subsidy between customers.

National Electricity Objective

In the draft determination document, the AER considered it appropriate to allow the NSW DNSPs to charge prices which reflect the efficient costs of providing public lighting services. The AER noted that the national electricity objective is intended to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity. The AER considered that it is appropriate to apply the NEL revenue and pricing efficiency principles to alternative control services.

Efficient and cost reflective prices were produced via the annuity method for the June 2008 proposal. EnergyAustralia has established that the AER's limited RAB roll-forward would result in customers being charged more than the June 2008 prices. Further, in its draft determination the AER's stated that a DNSP should be able to recover at least the efficient costs incurred for alternative control services[296]. EnergyAustralia believes that a proper application of the NEL revenue and efficiency pricing principles should result in customers being charged prices that accurately reflect the cost of the provision of services.

EnergyAustralia's proposed price list calculated using the annuity method as per our June 2008 proposal is more consistent with the National Electricity Objective than the AER's RAB roll-forward approach.

7.5 Alternative options considered by EnergyAustralia

The AER has indicated that valuing components at replacement cost was the major consideration in its rejection of the annuity method for existing stock. EnergyAustralia carried out two alternative pricing methodologies to demonstrate that other options exist for setting prices of installed assets that do not use a RAB roll-forward method. These options are derivations from EnergyAustralia's original annuity method.

Option 1 – 2004 costs for obsolete components

This method is similar to the annuity method in the June 2008 proposal, with the exception that obsolete components have 2004 material and installation costs applied to the annuity model. This means that prices for installed assets are based on the capital and labour costs that applied in 2004 and were approved by IPART. All prices for current (new) components are based on material and installation costs as at 2008 costs.

The benefit of this approach is that it does not require detailed age data because it uses the annuity approach. However, unlike the June 2008 proposal, this option ensures that customers with large amounts of obsolete components installed pay prices based on historic costs (as at 2004) rather than prices determined on the basis of new costs (as at 2008).

This method protects the price signals that are important to drive efficient public lighting choices in future.

Option 2 – 25 annuity term

This second option also uses an annuity method that was proposed in June 2008. However the economic life that was assumed for all components (excluding lamps) was increased from 20 years to 25 years. By extending the term of the annuity payments, the annual capital charges (and prices) were reduced for customers. EnergyAustralia does not believe that

[296] Draft Determination, p336

the economic life of components is 25 years. The 20 year figure was increased as a simple means of discounting prices for customers. In this way the additional 5 years of the annuity term can be considered as a proxy for the rebate that EnergyAustralia proposed in its June 2008 proposal.

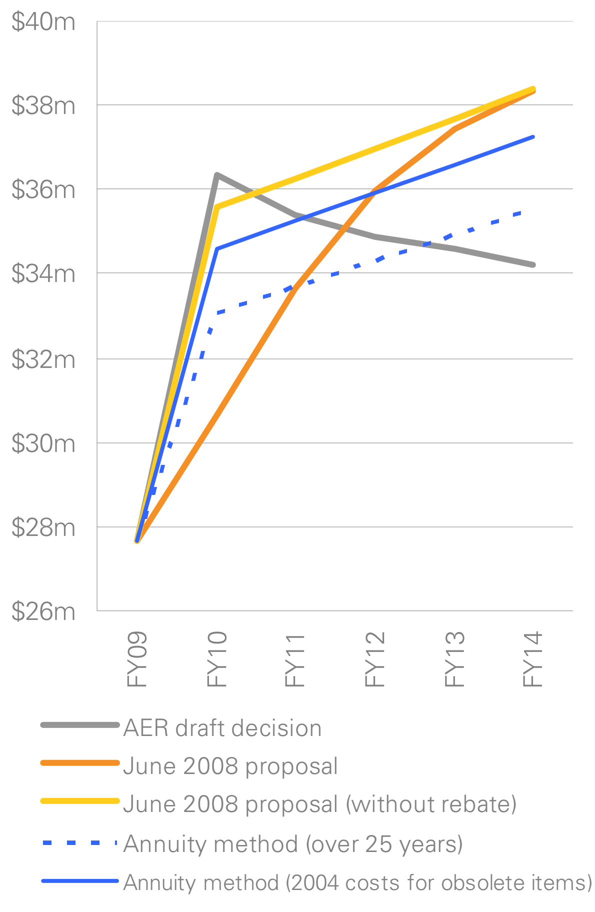
The results of these two options can be compared to the June 2008 proposal and the AER's limited RAB roll-forward for existing assets.

Figure 7.3 shows that the AER's limited RAB roll-forward method produces the highest prices for customers compared to all the methods considered, and that EnergyAustralia's original annuity approach using 2008 costs with a rebate produces the lowest prices for public lighting customers.

It should be noted that the limited RAB roll-forward revenue path shown does not include the replacement of stock from 1 July 2009. Therefore, the expected costs to public lighting customers under this option would actually be higher than is indicated by Figure 7.3.

Figure 7.3 demonstrates that there is a range of alternative pricing methodologies that could be used to minimise customer price impacts, that do not involve application of a data intensive roll-forward method to calculate prices, and do not result in two separate prices lists. EnergyAustralia requests the AER to consider these alternatives before committing itself in its forthcoming determination to a data intensive limited RAB roll-forward approach to public lighting prices.

Figure 7.3 Comparison of pricing options



EnergyAustralia continues to assert that the annuity method applied to calculate prices for both old and new components is the most efficient means of calculating cost reflective prices. Furthermore, we argue that it remains the best method to signal the relative costs of old and new equipment and therefore encourages efficient investment choices in the future.

7. Control mechanism for alternative control services (continued)

7.6 Response to technical and other issues

Asset lives poles

The AER considers that 35 years is the appropriate age for public lighting supports because such an assumption is consistent with other jurisdictions. EnergyAustralia, however, does not accept that supports should have an economic life of 35 years applied to them instead of the 20 years as modelled in the June 2008 proposal.

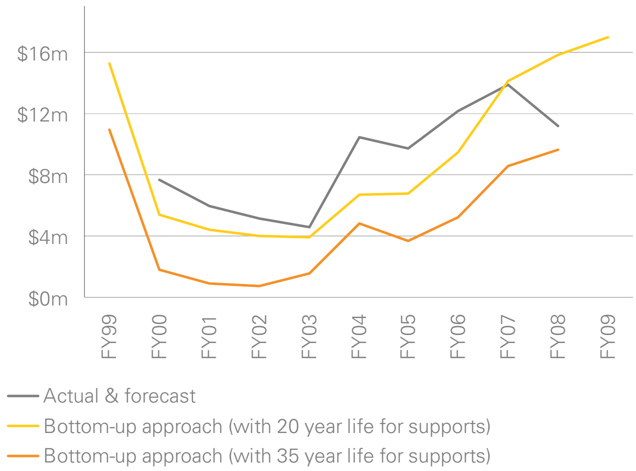
Other jurisdictions do not necessarily have the same conditions as the EnergyAustralia network region. For example, equipment located in coastal and industrial regions experiences a more rapid deterioration due to corrosion from salt spray, sand blast and sulphate soils. Most of the supports that EnergyAustralia charges customers for are constructed from steel and are more susceptible to these types of impacts. The AER must consider asset condition data before proceeding with application of this assumption. Extending the life of steel supports beyond 20 years will require operating expenditure in addition to what was originally forecast in the June 2008 proposal.

As part of the 18 December information request from the AER, EnergyAustralia carried out a bottom up analysis of public lighting capital expenditure over the last 10 years. This analysis used the same method to derive the installation date, and hence the remaining life of all components in the public lighting database. The assumed economic life for brackets and luminaires was 20 years, and for lamps it was 2.5 years. Two scenarios were carried out for supports; one with an economic life of 20 years, and one with an economic life of 35 years. Figure 7.4 shows that capital expenditure under the bottom up analysis more closely matches actual expenditure where supports are assumed to have an economic life of 20 years.

The change in the expected life of public lighting supports has ramifications for replacement of supports mid-way through the life of the second set of lighting assets that are connected to that support (assuming supports have a life of 35 years and all other assets have an expected life of 20 years).

EnergyAustralia considers it preferable from an economic and technical standpoint to align the standard lives of public lighting assets.

Figure 7.4 Public lighting capital expenditure



Bulk lamp replacement

EnergyAustralia's bulk lamp replacement program is based on a replacement cycle of a lamp life of 2.5 years. This replacement program was developed on the basis of lamp failure rates and is supported by a report from Wilson Cook & Co[297].

On page 338 of the draft determination, the AER states that the bulk lamp replacement programme should be carried out over 3 years without providing technical justification for this change. EnergyAustralia's bulk replacement program is designed to limit the average failure rate of lamps. To change the bulk replacement from 2.5 to 3 years will have an adverse impact on the amount of required spot replacement and, consequently, the total operating cost.

EnergyAustralia's June 2008 proposal balances the bulk and spot replacement cost. The AER has not considered this balance and should do so when it makes its draft determination. If the AER, maintains that bulk lamp replacement should occur on a 3 year cycle in its draft determination, EnergyAustralia will need to revise its proposal

[297] p11 Review of EnergyAustralia's Public Lighting Capital and Operating Expenditure (Wilson Cook & Co) August 2005

for alternative control services to incorporate higher spot lamp replacement costs to cater for the higher expected failure of lamps in service.

Calculation of Rate 4

The AER has indicated that it does not consider the proposed calculation of Rate 4 to be appropriate. Rate 4 applies to customers that request replacement of an asset before that asset has reached the end of its technical life and been fully depreciated.

In its June 2008 proposal, EnergyAustralia proposed that Rate 4 be calculated by applying additional capitalised installation costs to brackets and luminaires as a proxy for the foregone depreciation costs of the asset. Brackets and luminaires are assumed to be installed at the same time. Normally 90% of the capitalised installation cost is attributed to the bracket, and 10% to the luminaire. Under the proposed Rate 4 method, retrofit prices would have 100% of the installation cost applied to the bracket and a further 100% of the original installation cost applied to the bracket.

EnergyAustralia accepts that there are better ways to calculate a proxy for the lost asset value of a replaced component. EnergyAustralia has revisited these calculations and has identified a new approach to produce Rate 4 component prices. Under this new approach, the capital cost for each component (includes materials and capitalised overheads) is depreciated by 75% to take into account the likely age of assets that are replaced under Rate 4. By this, EnergyAustralia assumes that most assets being replaced before the end of their standard lives will be three quarters through their standard life. This is consistent with the recommendation specified in the draft determination which stated that unless the remaining life of an asset is more than 10 years then its default age should be assumed to be at least three quarters of its assumed life.

Under EnergyAustralia's new rate 4 method, the remaining capital value is converted to an annuity using the same approach as in the June 2008 proposal. This annuity capital charge is added to the final Rate 1 prices for brackets and luminaires, to give a new Rate 4 price. As such the new Rate 4 prices are 25% higher than the Rate 1 prices.

EnergyAustralia considers this approach to be a fair and reasonable method of estimating the lost depreciation associated with early replacement of public lighting components. It should be noted that, consistent with the AER's draft determination document, this method should apply unless data is found that suggests that the remaining life of the asset in question is more than 10 years.

Annual compliance

The AER considers that compliance with the control mechanism can be demonstrated through an annual approval of changes in the schedules of prices. Each DNSP must submit its revised schedules of prices, that will apply in a regulatory year, 9 weeks prior to the commencement of each regulatory year in the next regulatory control period.

EnergyAustralia considers that this proposed compliance regime is appropriate.

Service levels

EnergyAustralia agrees that DNSPs should be able to charge prices that reflect the efficient costs of providing the level of service set out in the NSW Public Lighting Code. We maintain that the annuity method is the best means of achieving efficient cost reflectivity.

EnergyAustralia notes that any monitoring of actual service performance against the requirements of the Public Lighting Code is distinct from mandatory compliance with this Code, and that should mandatory standards be enforced, EnergyAustralia will seek a variation to its price list to accommodate any changes in costs.

Part III – Pricing & Negotiating frameworks

1. Procedures for Assigning customers to tariff classes

SUBMISSION

EnergyAustralia has not revised its June 2008 proposal regarding procedures for assigning customers to tariff classes.

Chapter1 of Part III remains EnergyAustralia's June 2008 proposal remains EnergyAustralia's current proposal in relation to the procedures for assigning customers to tariff classes. This chapter is EnergyAustralia's submission in relation to the AER's draft determination and supports EnergyAustralia's current proposal and is supported by this chapter.

Rule requirements

A distribution determination is predicated on the AER's decision on the procedures for assigning customers to tariff classes, or reassigning customers from one tariff class to another (including any applicable restrictions) (Clause 6.12.1(17))

Our June 2008 proposal

EnergyAustralia's Regulatory Proposal (Part III, chapter 1) included its proposed approach to customer tariff assignment and reassignment. This approach is consistent with EnergyAustralia's current practice and is consistent with the principles set out in Transitional Rule 6.18.4 and other relevant clauses. It is also the process which has been accepted by IPART during the course of the current regulatory determination.

AER's draft determination

It appears that the AER formed its own view of procedures for assigning customers to tariff classes, without having regard to EnergyAustralia's proposal. The AER's proposed approach is outlined in Chapter 1 and Appendix A of its draft determination. The AER notes that it had regard to the principles in Transitional Rule 6.18.4 when developing its proposed procedures.

Our response to the AER's draft determination

EnergyAustralia does not accept the AER's decision. It has addressed the following matters as raised in the AER's determination.

- Section 1.1 sets out the reasons why the AER was incorrect in not considering EnergyAustralia's proposed procedures for assigning customers to tariff classes.
- Section 1.2 sets out the reasons why the AER's proposed approach appears to prevent EnergyAustralia from continuing to progressively implement cost reflective tariffs such as Time of Use (ToU) and the flow on implications of this.
- Section 1.3 sets out the reasons why the AER's procedures are outside the power conferred by clause 6.18.4 of the Rules and are unreasonable and unnecessarily onerous.

1.1 The AER did not consider EnergyAustralia's proposal

The AER's draft determination makes no reference to EnergyAustralia's proposal for procedures relating to the assignment of customers to tariff classes (Part III, chapter 1 of our Regulatory Proposal).

The AER notes that Transitional Rule 6.12.1(17) requires it to make a decision on the procedures for assigning or re-assigning customers to tariff classes as part of its distribution determination. The AER has developed the proposed procedures without taking into account the DNSP's considerations or proposals.

EnergyAustralia's comments

It is incumbent on the AER to consider EnergyAustralia's proposal

There is no indication that we can find that the AER has given any consideration to EnergyAustralia's proposal in relation to assigning customers to tariff classes. At page 20 of its draft determination, the AER states:

> The AER notes clause 6.12.1(17) of the transitional chapter 6 rules requires it to make a decision on the procedures for assigning or re-

> assigning customers to tariff classes. There is no requirement on DNSPs to propose such procedures and consequently the AER must develop the required procedures.

The AER has therefore applied the principles of 6.18.4 to the exclusion of the circumstances of EnergyAustralia's business and environment and without regard for the current regulatory arrangements or EnergyAustralia's current practice and our proposal to continue those arrangements.

It appears that the AER has failed to make a decision on EnergyAustralia's proposed procedures.

The failure to consider EnergyAustralia's proposal is contrary to Transitional Rule 6.10.1, and the failure to make a decision (with reasons) with respect to it is contrary to Transitional Rules 6.12.3 and 6.12.2. In our view the AER was required to consider the regulatory proposal and to only depart from that proposal (subject to the Rules, Law and having regard to submissions) to the extent necessary to enable it to be approved in accordance with the Rules.

The AER is correct in its proposition that there is no requirement on the service provider to propose such procedures. The AER has also correctly stated that clause 6.18.4 of the Rules sets out the principles to which the AER must have regard in formulating procedures that NSW DNSPs are required to follow when assigning or re-assigning customers to tariff classes.

However the AER is incorrect in concluding that it must develop its own procedures using the 6.18.4 principles as its sole consideration. The reasoning does not consider the position where a service provider does propose such procedures, either in a proposal or submission to the proposal.

EnergyAustralia prepared a detailed and considered proposal (as part of the pricing and negotiating frameworks section of its proposal) on its approach to assigning customers which is consistent with:

- the principles in Transitional Rule 6.18.4;
- its current approach to assignment and reassignment; and
- IPART's 2004-09 determination – in particular its price setting arrangements for network tariffs and network pricing principles.

The Rules require the AER to make a determination on the process that EnergyAustralia has proposed. This includes making a draft determination which allows all stakeholders to make comment prior to a determination in its final form.

As a minimum, EnergyAustralia would ask the AER to assess the June 2008 Proposal in regards to tariff assignment and reassignment and allow all stakeholders the opportunity to respond to this assessment prior to making a determination in its final form.

1.2 The AER proposal's impact on tariff reform and initiatives

The AER's proposed procedures appear to limit reassignment to instances where:

- an existing customer's load characteristics or connection characteristics (or both) have changed such that it is no longer appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned; or
- a customer no longer has the same or materially similar load or connection characteristics as other customers on the customer's existing tariff.

This is a departure from the current pricing approach which has been actively promoted by IPART as a means of improving the cost reflectivity of network prices.

EnergyAustralia's comments

Perceived lack of flexibility in reassignment of customers

Clause 5 of the AER's proposed procedures note:

> If a DNSP believes that an existing customer's load characteristics or connection characteristics have changed such that it is no longer appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned or a customer no longer has the same or materially similar load or connection characteristics as the other customers on the customer's existing tariff, then the DNSP may re-assign that customer to another tariff.

There is no further explanation of this clause, particularly whether or not it is intended to be restrictive. As currently drafted the clause would most likely be interpreted as only applying a restriction on the assignment of customers in the circumstances set out in the clause and no other.

If this clause is not meant to be restrictive, we believe customers and DNSPs would benefit from a clarification to that effect.

If the AER intended this clause to be restrictive (ie. this represents the only circumstances which customers can be re-assigned), this would limit the principles in 6.18.4. We do not believe this was the intent of policy makers in the development of the Rules.

Transitional Rule 6.18.4(a) requires the AER to have regard to the principle that customers should be assigned based upon one or more of the following factors:

- the nature and extent of the customer's usage;
- the nature of the customer's connection to the network; and
- whether remotely-read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

We do not consider this list to be exhaustive. Nor do we consider it to be a basis for restricting reassignment of customers. While Rule 6.18.4(a) requires the AER to have regard to the listed principles; it does not appear to prohibit the AER from considering other matters. Otherwise there would be little benefit in developing procedures outside the Rules.

If there are other matters which are relevant, pertinent and consistent with the listed principles, it is open to the AER to have regard to them when designing the reassignment procedures that apply.

Tariff classifications are generally based on these several factors but in some cases a customer's load or connection characteristics might meet the requirements of a number of different tariff classes. In those cases it may be necessary to have regard to further characteristics to determine the tariff that should apply.

For example, a small load connected to the low voltage network could be placed on our public lighting tariff, our Domestic non-ToU tariff, our Business non-ToU tariff, or our LV Energy40 ToU tariff. Determining the correct tariff requires a consideration beyond the points given under Transitional Rule 6.18.4(a). The additional characteristics to which EnergyAustralia would have regard are the meter type and whether the customer's use is business or residential.

As indicated above, EnergyAustralia considers that in the absence of a statement that clause 5 is intended to set out exhaustively when reassignment may occur, it is not so restrictive. However, if the AER does intend clause 5 to limit reassignment to the circumstances contemplated in that clause, EnergyAustralia believes it is incumbent upon the AER to explain how this limitation promotes the efficient operation and use of electricity services for the long term interests of consumers.

Limiting customer reassignment to instances where the customer has changed usage or connection characteristics:

- does not allow the customer to voluntarily move to another tariff class;
- does not allow either a retailer or a DNSP the opportunity to develop tariff products that move toward cost reflective pricing (such as time of use tariffs);
- does not allow EnergyAustralia to pursue the deferral of network capital expenditure through tariff initiatives.

EnergyAustralia's June 2008 proposal included a set of procedures consistent with the principles in 6.18.4 but which specifically recognised that:

- EnergyAustralia may offer voluntary tariffs from time to time and, should the customer or their retailer accept this offer, they may be reassigned.
- New connections and upgraded connections must install a type 5 or better meter.
- There may be a time differential between the new or upgraded connection, the installation of the new meter and the reassignment of the tariff.

EnergyAustralia proposes that voluntary tariffs be explicitly mentioned in any tariff re-assignment policy. The tariff re-assignment policy would only apply to those customers where the voluntary tariff expired, or the customer no longer wished to participate on the voluntary tariff. In both cases, they would revert to a default tariff, consistent with the re-assignment policy.

1. Procedures for Assigning customers to tariff classes

(continued)

The AER's approach may prevent EnergyAustralia from continuing to progressively implement ToU tariffs where metering permits

Consider where a customer's induction disc meter is replaced with a smart meter, and this is done by the DNSP (or Retailer). Under these circumstances, the AER's draft tariff re-assignment policy does not allow customers to be converted to ToU forms of pricing.

In the 2004 determination, EnergyAustralia proposed, and IPART approved, expenditure to install manually read interval meters at customers' premises with an annual consumption of 15 MWh or more. The proposed expenditure was justified on the basis that those customers would have ToU tariffs applied and the positive effects of demand management on the whole supply chain would outweigh the cost of the metering installation.

EnergyAustralia's Network business' ToU program is now well advanced. Around 330,000 customers now have an interval meter (out of approximately 1.6 million customers). Substantial resources are being committed by EnergyAustralia, and many Tier 2 Retailers in recent years, to permit ToU prices to be billed to customers. However many customers who have an interval meter installed may not have moved to a new tariff. EnergyAustralia intended to progress this over the 2009-14 regulatory control period.

It should be noted that the cost of manually read interval meters has reduced to the point where they have become a prudent alternative to rotating disk accumulation meters for general use.

In addition, metering and communications technology is advancing very rapidly. With the imminent availability of low cost communications such as WiMax, remotely read metering has the potential to become cost competitive in certain circumstances during the period of the 2009-14 regulatory control period.

Remotely read metering may well be introduced on a widespread basis during this period as the result of a regulatory obligation or requirement. However there is also significant potential that it may become beneficial for customers and industry alike for it to be introduced either by a Retailer, to create new tariff products for certain classes of customer, or by a DNSP, as a response to managing demand in a specific locality.

The AER's procedures are unnecessarily onerous and allow little flexibility for tariff innovation

In the event that remotely read metering were installed at the instigation of the DNSP or a Retailer without a regulatory obligation, the AER's proposed tariff reassignment procedure would prevent the implementation of cost reflective tariffs and would thereby stifle the adoption of modern metering and demand management technology by the supply industry.

The AER's proposed procedure does not appear to allow for reassignment even in the event that new meters are installed as a consequence of a regulatory obligation. The installation of a new meter in itself cannot be regarded as a change in either a customer's load or connection characteristics.

The AER's apparent restriction on tariff reassignment would represent a significant backward step in the tariff reform program that EnergyAustralia and other industry participants have been promoting. It would also prevent supply chain benefits being obtained from the industry's investment in manually read interval meters, which IPART approved in its last determination.

As noted above, the AER's tariff re-assignment methodology also does not allow for customers to voluntarily move to more innovative rates, such as EnergyAustralia's dynamic peak pricing tariffs. EnergyAustralia has plans for a number of new innovative voluntary tariffs to pay customers to reduce demand, but the AER's tariff re-assignment policy looks set to prohibit these initiatives.

EnergyAustralia requests that the AER accept EnergyAustralia's proposed procedures and revise its procedure consistent with EnergyAustralia's proposed procedures set out in its June 2008 proposal.

1.3 AER's system of assessment, review and dispute resolution is outside the power conferred by the Rules and is onerous and unnecessary

The AER's proposed procedure requires the DNSP to notify the customer concerned, in writing, of the tariff class to which the customer will be re-assigned, prior to the re-assignment occurring.

If a customer objects to the proposed re-assignment, the relevant DNSP must reconsider the proposed re-assignment in light of the elements contained in the AER's procedure, and notify the customer in writing of its decision and the reasons for that decision.

If the objection is not resolved to the satisfaction of the customer, the customer or the DNSP may request the AER to decide which of the DNSP's tariff classes the customer should be assigned.

The AER must notify the customer and relevant DNSP of its decision in respect of a dispute. If the AER does not give notice of its decision within 30 business days of receiving the request, the AER is to be regarded as having decided that the customer should not be re-assigned.

EnergyAustralia's comments

It is unclear how the "system of assessment and review" applies and to whom it applies

Clause 6 of the AER's proposed procedure notes that the EnergyAustralia is required to "notify the customer concerned" if we are considering reassigning a customer to another tariff class.

On a practical note, EnergyAustralia's Network business is not privy to the tariff assignment applied by Retailers to their customers. EnergyAustralia's network business has in practice notified Retailers in advance of tariff re-assignments for bulk transfers. The best example of this has been EnergyAustralia's ToU roll out, where we would transfer customers in a region to ToU after having rolled out interval meters to that area. The Retailer in turn may or may not notify the customer of any retail tariff change depending whether they pass through the tariff.

In many cases, where EnergyAustralia has applied a ToU tariff after an interval meter has been installed, we have discovered that the retailer has retained a flat tariff to the customer. This information has been revealed through ad hoc market research direct to the customer.

EnergyAustralia is therefore not clear as to whether the AER procedures require it to inform the customer or the retailer (or both) and which party is subject to the review and assessment provisions.

EnergyAustralia would like the AER to explain how its proposed approach would apply in this circumstance.

The tariff re-assignment provision as it stands would appear to set up a regime where the AER becomes deeply involved in the minutia of tariff assignment and reassignment.

The AER's procedures are beyond the power given to the AER under the NEL and the Rules to resolve disputes

Transitional Rules 6.18.4 and 6.12.1(17) clearly contemplate procedures to be followed by a DNSP. This includes the procedures to be followed in relation to assessment and review by the DNSP of a customer's tariff assignment.

The principles in Rule 6.18.4(a)(4) do not contemplate or require development of a procedure that effectively introduces external review by a person such as the AER. These principles do not empower or require the AER to create or impose the proposed dispute resolution procedure.

The AER's primary dispute resolution powers are outlined in Part 10 of the NEL. A disagreement between a DNSP and a customer regarding tariff assignment, including a DNSP's "assessment and review" of its decision, is arbitrable under that Part.

There does not appear to be any basis under the NEL or Rules on which the AER can create and impose its dispute resolution procedure as proposed. More specifically, there is nothing in the NEL or the Rules (including those provisions setting out the functions and powers of the AER) that allows the AER to derogate from the Part 10 arbitration procedure that would ordinarily apply.

If a customer is not satisfied with the assignment (following internal assessment and review under the procedures) the

1. Procedures for Assigning customers to tariff classes
(continued)

customer may bring an access dispute under Part L of the Rules and Part 10 of the NEL.

We request that the AER provide a clear indication of the basis on which the AER believes it is empowered to create and impose its proposed dispute resolution procedure. In the absence of any compelling justification, the proposed procedure is inconsistent with Part 10 of the NEL and appears to be beyond the power of the AER to impose.

The AER's proposed procedures are in any event unreasonable and onerous on the DNSP

No regulatory justification, or any other reasons, have been put forward to justify the proposed procedures. The proposed dispute resolution procedure includes elements that are onerous and unfair as discussed below.

Clause 11 – Reasons for decision

EnergyAustralia would be required to provide reasons in writing for any decision made under Clause 8 of the AER's proposed procedures. However the AER has not imposed any similar requirement on itself in relation to a decision under Clause 11. The giving of proper reasons for a decision is well recognised as a significant component of fairness and transparency in decision making. The AER should not exempt itself from a requirement to give reasons.

Clause 12

Clause 12 of the AER's proposed procedure deems the AER to have decided not to allow the re-assignment if it has not made a decision within 30 business days. This disadvantages the DNSP and provides no incentive for the AER to turn around disputes in an efficient manner. We see no reason why we should be disadvantaged as a result of unnecessary delays on the AER's part. In addition, the absence of a decision from the AER has the potential to foster sentiment that the AER has not given a full and proper (or even any) consideration of the issue or of the views of the parties on the matter.

Clause 12 is also inconsistent with Part 10 of the NEL which requires the AER to make a determination in relation to an access dispute and does not provide for a default decision against the DNSP if a decision cannot be made within a specified time.

The AER is strongly urged to reconsider the proposed arrangements.

The presumption should be that the DNSP is entitled to change customer tariffs in accordance with the approved arrangements. Provided that, on review by customer request, the DNSP could demonstrate that it had followed an approved procedure such as that already articulated in EnergyAustralia's regulatory proposal, the AER should then support the DNSP's decision.

2. Indicative prices

REVISED PROPOSAL

EnergyAustralia has revised the indicative prices for Network Use of System charges for the next regulatory control period included in its June 2008 proposal. This chapter replaces Chapter 2 of Part III of the June 2008 proposal.

Rule requirements

A DNSP's Regulatory Proposal must provide indicative prices for Direct Control Services for each year of the regulatory control period.[298]

Our June 2008 proposal

EnergyAustralia provided indicative NUoS prices on an average c/kWh basis for each year of the regulatory period.

AER's draft determination

In its draft determination, the AER did not comment on EnergyAustralia's indicative prices, nor was it required to do so.

Our response to the AER's draft determination

EnergyAustralia has revised its indicative prices as a consequence of:

- X-factors in this revised proposal;
- the AERs draft revenue decision for TransGrid revenues for the 2009-14 period;
- the NSW government's recent mini-budget that outlined payments to be made by DNSPs to the NSW Climate Change Fund; and
- EnergyAustralia's energy forecast in this revised proposal.

[298] Clause 6.8.2(c)(4) Transitional Rules.

The indicative prices outlined in this chapter recover revenues for EnergyAustralia's distribution and transmission networks, transmission payments to TransGrid for use of their transmission network, and revenues to cover obligations to the NSW Government's Climate Change Fund. There are a number of assumptions that have been made to derive these indicative prices. It should be noted that these prices are indicative only and are not binding. Rather, they are provided as a guide to network price levels over the next regulatory period.

Actual prices are dependent on:

1. The AER's final decision relating to this regulatory proposal for 2009-14;
2. The AERs final decision relating to TransGrid's regulatory proposal for 2009-14;
3. Any decision of the NSW Government to reduce or increase in size the Climate Change Fund during the 2009-14 period;
4. Any pass through events that may arise during the remainder of the 2004-09 or the 2009-14 regulatory periods, in particular a roll out of advanced metering infrastructure;
5. Changes in cost allocation between tariff classes brought on by changing patterns of network use between customer groups; and
6, Revealed CPI during the 2009-14 regulatory period.

Indicative prices have been shown in nominal cents per kWh for energy consumed, but it should be noted that actual prices, depending on the specific tariff, consist of a number of components of fixed, energy and capacity charges.

A general NUoS price increase of 40 percent is required at 1 July 2009, followed by ongoing annual increases of 16 percent for the remaining years of the regulatory period. These indicative price changes do not align with the X-factor calculations in chapter 13 of Part I as they include estimates of TransGrid's charges and other components. These average price increases are required to fund EnergyAustralia's substantial capital and operating programs as assessed by the AER. These programs are explained in EnergyAustralia's June 2008 proposal and as revised in this document.

2. Indicative prices (continued)

EnergyAustralia has long advocated cost reflectivity in network pricing so that economic signals conveyed to customers will influence their consumption patterns. As a consequence, domestic customers can expect to see progressively larger price increases compared to other tariff classes, to accompany their relatively larger contribution to peak demand associated with increased air-conditioning penetration. Domestic customers are making up a greater proportion of the network peak, and network peak drives augmentation capital expenditure. To signal this cost, domestic customers will face higher network charges reflecting that growing contribution to peak demand.

Public lighting network use of system prices will continue to remain higher that other low voltage tariffs, because of their poor power factor performance. Poor power factor means they contribute more in relative terms to peak demand.

However, as the network becomes more consistently summer peaking, the contribution of street lighting load to capital expenditure will diminish. Street lighting tariffs will therefore see marginal price changes over the regulatory period, relative to other tariffs.

Customers connected to the high voltage network (11kV) or to the subtransmission network (33kV, 66kV and 132kV) will continue to experience lower network charges. This is because these customers use a smaller proportion of the network by virtue of being connected closer to EnergyAustralia's connection points to the transmission network. They also generally demonstrate a better load profile, being flatter in their usage patterns, and therefore contributing less, in relative terms, to network peak costs.

Figure 2.1 Indicative network prices (c/kWh nominal)[299]

	FY09	FY10	FY11	FY12	FY13	FY14
Domestic	6.0	8.5	10.0	11.6	13.8	16.3
LV Business	4.7	6.8	7.8	8.9	10.1	11.5
Public lighting & other unmetered	4.2	6.1	7.1	8.1	9.2	10.5
HV Business	2.9	4.0	4.7	5.3	6.0	6.7
ST Business	1.74	2.3	2.7	3.1	3.6	4.1
CRNP customers	0.9	1.25	1.49	1.7	1.9	2.2

299 Indicative prices for miscellaneous and monopoly fees is found in Attachment II.4E: Applying the Control Mechanism to Miscellaneous and Monopoly Services Indicative prices for public lighting SLUoS services is found in the June 2008 submitted RIN Template, Schedule 2.2.5. EnergyAustralia has not submitted revised SLUoS proposal as part of this revised proposal. Please refer to Chapter 7 of Part III of this proposal for more details.

3. Treatment of TUoS recovery

SUBMISSION

EnergyAustralia has not revised its June 2008 proposal, which outlines our approach to the recovery of TUoS costs through distribution pricing. EnergyAustralia's current proposal in relation to the recovery of TuOS costs remains Chapter 3 of Part III of the June 2008 proposal. This chapter is EnergyAustralia's submission in relation to the AER's draft determination and supports EnergyAustralia's current proposal.

Rule requirements

Clause 6.12.1(19) of the Transitional Rules provides that:

- A distribution determination is predicated on a decision on how the DNSP is to report to the AER on its recovery of TUoS charges for each year of the regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of charges in the prior year.

Clause 6.18.7 of the Rules provides that an over or under recovery is the difference between:

- the amount actually paid by the DNSP by way of transmission use of system charges in the previous regulatory year; and
- the amount passed on to customers by way of transmission use of system charges by the DNSP in the previous regulatory year.

Our June 2008 proposal

EnergyAustralia proposed a departure from the AER's standard control services guideline for the recovery of TUoS costs through distribution pricing, in Section 3.1 of Part III of our regulatory proposal.

In targeting a zero unders/overs balance for TUoS, we proposed forecasting the TUoS unders/overs balance for the current year (t-1). This is the process that has been followed with IPART, during the course of the current determination and is consistent with clause 6.18.7 of the Transitional Rules.

AER's draft determination

In its draft determination, the AER did not consider EnergyAustralia's proposal.

Appendix I of the AER proposal provides for the inclusion of the audited unders/overs TUoS balance from the previous financial year (ie. t-2) in setting prices for the following year.

Our response to the AER's draft determination

EnergyAustralia does not accept the AER's decision to only permit an audited TUoS balance in setting prices, for the following reasons:

- The AER has not correctly applied clause 6.18.7 of the Transitional Rules, which requires that the unders/overs balance of the previous regulatory year be used in setting prices for the following regulatory year.
- The AER's proposed approach departs from the current IPART framework without sufficient reason.

3.1 EnergyAustralia's proposal was not considered

The significant difference between EnergyAustralia's proposal and that of the AER is that the TUoS balance in setting prices targets an over/under recovery in the current year (t-1) rather than year (t-2).

EnergyAustralia's June 2008 proposal included EnergyAustralia's preferred approach to TUoS recovery. This approach was supported:

- legally through the correct interpretation of the Transitional Rules, and
- from a policy perspective due to its consistency with the approach applied by IPART and its appropriateness for targeting a nil balance by the end of year "t".

The AER was under an obligation to consider EnergyAustralia's proposed procedure for TUoS recovery and appears to have failed to do so.

3. Treatment of TUoS recovery (continued)

The AER's decision is also incorrect because it has applied a definition of over recovery which is inconsistent with the Rules. Clause 6.18.7(c) specifies that the extent of the over or under recovery which must be considered when determining the TUoS recovery amount to be passed on to customers for a regulatory year is to be determined by reference to the previous regulatory year. The AER has incorrectly interpreted this to mean the most recently completed year, rather than the current year. Although IPART have not been subject to 6.18.7 of the Rules, their convention has been to define the previous regulatory year to be the one immediately preceding the regulatory year for which prices are calculated.

The AER's decision was also unreasonable because it did not properly consider the current practice followed by DNSPs or the implications of the proposed approach. Specifically, it did not have proper regard to the following policy considerations:

- The approach which EnergyAustralia has proposed is the same as that which has been followed under the current regulatory framework. The AER's proposal is inconsistent with that which had been adopted by IPART for good reasons.
- The AER's approach would mean that significant overs and unders balances could be carried unnecessarily for an additional year. This would mean that the forecast $14 million under-recovery of TUoS currently being carried by EnergyAustralia for the 2008/9 year would not be recovered until 2010/11, rather than in 2009/10.

An outcome of this additional delay in recovery is that the variation in TUoS recovery is likely to exacerbate fluctuations in prices.

During the course of setting prices for the 2009-10 financial year, it became apparent that there is the potential of significant variation in transmission charges as a result of variation of settlements surpluses and pass through items.

Such variations result in an equivalent variation in the TUoS prices to customers. This is a particular issue for those large customers for whom the transmission charge comprises a significant proportion of the total network charge. The stability of network prices is an important objective which should not be overlooked.

EnergyAustralia believes that the AER's approach is not consistent with the Rules. The Rules require the targeting of forecast zero unders/overs TUoS balance. Use of lagged quantities as proposed by the AER does not allow a targeting of a zero balance, as it does not allow for adjustments from the current year.

Inconsistency with AER's Guidelines

EnergyAustralia's notes that the AER's decision is consistent with its *Guidelines on Control Mechanisms for direct control services*, published in February 2008. However to the extent that this guideline proposed to incorrectly apply the rules it could not be lawfully applied by the AER.

EnergyAustralia submits that the AER should reconsider its decision in relation to TUoS recovery and adopt EnergyAustralia's proposed approach which correctly applies the Transitional Rules, is consistent with the current IPART framework and reflects good regulatory practice.

4. Pricing methodology

REVISED PROPOSAL

EnergyAustralia has revised its regulatory proposal to include a corrected pricing methodology. This is set out in Attachment III.4A of this revised proposal.

This Chapter together with Chapter 4 of Part III of the June 2008 proposal and the Transmission Pricing Methodology attached at Attachment III.4A now comprise EnergyAustralia current proposal and proposed pricing methodology for its prescribed (transmission) standard control services.

Rule requirements

The AER's draft determination is predicated on a decision, for EnergyAustralia's prescribed (transmission) standard control services, on the proposed pricing methodology, in which the AER either approves or refuses to approve that methodology and sets out reasons for its decision (Clause 6.12.1(20))

Our June 2008 building block proposal

EnergyAustralia submitted a proposed pricing methodology as part of its regulatory proposal.

During its assessment the AER' identified several unintended errors which EnergyAustralia addressed by submitting a corrected methodology.

AER's draft determination

The AER approved EnergyAustralia's pricing methodology based on its assessment of EnergyAustralia's corrected pricing methodology.

Our response to the AER's draft determination

EnergyAustralia agrees that the pricing methodology referred to in the AER's draft determination is appropriate. We have therefore formally revised our regulatory proposal to include the corrected pricing methodology.

4.1 Minor variations to June 2008 proposal proposed pricing methodology

The AER accepted EnergyAustralia's corrected pricing methodology

The AER noted that EnergyAustralia re-submitted its proposed pricing methodology on 28 October 2008 to clarify components of its cost allocation methodology.

EnergyAustralia's response

We wish to make clear that the corrected methodology provided by EnergyAustralia on 28 October 2008 did not constitute an amendment to our regulatory proposal at that stage.

However we understand that the AER was satisfied with the additional information clarifying some elements of the Transmission Pricing Methodology.

We have consequently revised our regulatory proposal to address the matters raised in the AER's draft determination.

Attachment III.4A of our revised proposal reflects these discussions with the AER and the matters raised in the draft determination.

We note that our revised Transmission Pricing Methodology differs to what is provided at Appendix T of the AER's draft determination.

The AER has attached EnergyAustralia's proposed Transmission Pricing Methodology submitted as part of its June 2008 proposal (ie the uncorrected version), rather than the version accepted by the AER. We assume this to be an inadvertent error, but request clarification from the AER that this is the case

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5. Negotiating framework; Negotiated distribution services; and Negotiable component criteria

REVISED PROPOSAL

In respect of the negotiable component criteria the AER must determine and EnergyAustralia must apply in negotiating terms and conditions of access, EnergyAustralia has only revised its original proposed approach and subsequent submission in one respect, by strengthening a particular aspect.

That aspect involves a clear carve-out from the pricing criteria where prices are regulated through other means (such as IPART's Capital Contributions Determination or regulation of monopoly services).

EnergyAustralia otherwise maintains all of the matters raised in its original proposal and submission.

This chapter addresses the matters raised by the AER in its draft determination and the reasons why EnergyAustralia has largely maintained its original proposal and submission in light of the matters raised.

This chapter together with Chapter 5 of Part III of the June 2008 proposal now constitute EnergyAustralia's current proposal in relation to Negotiated Distribution Services Criteria (NDSC) and Negotiable Component Criteria (NCC).

Rule requirements

The AER's distribution determination is predicated on a decision in which the AER decides EnergyAustralia's negotiated distribution service criteria (NDSC) and negotiable component criteria (NCC) (clauses 6.12.1(16) and (16B)).

Our June 2008 proposal

EnergyAustralia's Pricing and Negotiating Frameworks proposal (Part III, chapter 5) proposed that the AER adopt the Negotiated Distribution Service Principles in clause 6.7.1 and Negotiable Component Principles in clause 6.7A.1 as the appropriate NDSC and NCC respectively.

AER's proposed criteria and our submission on that proposal

The AER published its proposed negotiable component criteria and negotiated distribution service criteria together with an issues paper in June 2008.

EnergyAustralia made a submission in relation to the proposed criteria in which it recommended three changes to the proposed criteria.

Briefly, these were:

- To delete criterion 1 that the terms and conditions of access should promote the achievement of the national electricity objective, because it was unnecessary and created ambiguity given that the national electricity objective should already have been reflected in the principles underlying the criteria and in the criteria themselves. It also pointed out that the criterion incorrectly referred to the National Electricity Market Objective rather than the correct term National Electricity Objective.
- Criterion 2 should be amended to fully reflect the relevant principles in clauses 6.7.1(9) and 6.7A.1(10) because the AER's criterion did not include an important second limb of those principles, nor was the omission explained.
- Criterion 5 should be expanded to include reference to the capital contributions requirements applied by Part K of the Transitional Rules.

AER's draft determination

The AER made a minor change to its proposed NDSC and NCC. This was in response to EnergyAustralia's submission which noted that the terminology of clause 1 of the criteria referred to the National Electricity Market Objective and should be amended to National Electricity Objective.

The AER rejected all other issues raised by EnergyAustralia in its submission:

- The AER noted EnergyAustralia's objection to the inclusion of the first criteria in the NDSC and NCC. The AER noted that this criterion had been included in previous determinations. It also rejected EnergyAustralia's submission to amend the text referring to the promotion of the National Electricity Objective as it was linked to section 7 of the NEL.

- The AER rejected EnergyAustralia's submission that criterion 2 of the NDSC and NCC should also reference clauses 6.7.1(9) and 6.7A.1(10) on the basis that it was not included in negotiated service criteria for previous transmission determinations and in any case the AER is required to follow the Rules when applying the criteria.
- The AER rejected EnergyAustralia's submission to expand criterion 5 of the NCC so it includes the capital contributions requirements applied in Part K of the Transitional Rules. The AER believed there was sufficient flexibility in the criterion to make an amendment unnecessary.

Our response to the AER's draft determination

EnergyAustralia does not accept the AER's decision. It has addressed the following matters in the AER's determination:

- Section 5.1 sets out the amendment that EnergyAustralia now proposes to its original proposed approach (essentially a carve-out for regulated prices) and the reasons for it.
- Section 5.2 sets out the reasons why EnergyAustralia believes that the AER's proposed criteria do not comply with the Rules.
- Section 5.3 sets out the reasons why EnergyAustralia believes that the AER's considerations should not be tied to its own limited regulatory precedent.
- Section 5.4 sets out the reasons why EnergyAustralia believes its proposed changes provide greater clarity for EnergyAustralia and users in entering into negotiated arrangements.

5.1 Amendment to EnergyAustralia's original proposal – carve out for regulated prices

EnergyAustralia's original submission in relation to criterion 5

EnergyAustralia originally submitted that criterion 5 of the negotiable component criteria should be expanded that the price for a negotiable component need not be the price for that component in the DNSP's approved pricing proposal where that price has been set in the context of the framework for capital contributions charges applied by clause 6.21.4 of the Transitional Rules ("Capital Contributions Determination").

EnergyAustralia's revised submission in relation to criterion 5

In light of the AER's draft determination on negotiable components of direct control services, EnergyAustralia now submits that the above principle should be expanded to include other regulatory instruments that affect price. EnergyAustralia proposes an additional criterion 4A, to be inserted immediately before criterion 5 under the heading "Price of Services", as follows:

> 4A. If the price for a negotiable component is separately regulated, or the principles which affect the amount or money or non-monetary consideration payable in respect of that negotiable component are separately regulated, then the relevant regulation prevails over criteria 5 to 12. Such regulation includes (without limitation):
> (a) IPART's determination in respect of capital contributions, as referred to and applied by clause 6.21.4 of Chapter 11 for the NER;
> (b) regulation of charges for monopoly services;
> (c) Part 3 Division 4 of the Electricity Supply Act 1995 (NSW).

Explanation of EnergyAustralia's revised submission

Both EnergyAustralia's original and revised submissions are in recognition of the fact that for some negotiable components, price-related aspects are already covered by other regulatory instruments, and negotiations would in many cases be limited to non price-related aspects.

The principles in clause 6.7A.1, with which the negotiable component criteria must be consistent, are largely borrowed

5. Negotiating framework; Negotiated distribution services; and Negotiable component criteria (continued)

from the principles for transmission in clause 6.7.1, and largely emphasise negotiations on price. They were originally drafted in the context of a whole service (rather than merely components of it) being negotiable, and hence this would necessarily extend to negotiations on price.

As can be seen from our revised submission on Chapter 3 of Part II of this proposal (Negotiable Components of Direct Control Services), the concern with the AER's definition extends beyond IPART's Capital Contributions Determination and affects, for example, monopoly services, and s28 of the *Electricity Supply Act 1995* (NSW).

EnergyAustralia is concerned to ensure that nothing in Part DA derogates from, or casts doubt upon, these other regulatory principles.

Despite the emphasis of the Rules on price in this context, they still clearly give the AER the power and the flexibility to limit the application of the pricing principles in the manner suggested.

The AER's response to EnergyAustralia's original submission

The AER has stated in its reasoning that this specific reference is not necessary because criterion 5 does not apply if the terms and conditions of access for a negotiable component are so different as to warrant a determination of the price without regard to the criterion.

EnergyAustralia's response to the AER's draft determination

EnergyAustralia does not agree with the AER's decision or reasoning.

First, the phrase "unless the terms and conditions sought for the component are so different from those used for the purposes of establishing the approved pricing proposal *as to* warrant determination of the price without regard to this criterion" is clearly intended to apply in relation to components the price which is otherwise specified in the approved pricing proposal, but where in a particular case it is appropriate to depart from those prices.

An example of this might be where the commercial or technical conditions negotiated in a particular case (for example, in relation to insurance, limitations of liability or indemnities) are so different from the standard assumptions on which the price was originally based so as to warrant a different price.

This is an entirely different scenario from those to which EnergyAustralia's comments are addressed. The concept of terms and conditions which are different from those used to establish the pricing proposal does not lend itself well to covering price regulation through other means, in relation to matters not covered by the pricing proposal.

Secondly, some of the other criteria under the heading "Price of Services" are also potentially problematic from this point of view. For example, criterion 6 requires that "Subject to criterion 5, the price for a negotiable component must reflect the costs that the DNSP has incurred or incurs in providing that component …". Yet for monopoly services (some of which might be regarded as negotiable components under the AER's proposed definition), the prices are intended to be fixed regardless of whether they are cost reflective (noting that EnergyAustralia would argue that they are in many cases below cost).

The meaning of the phrase "Subject to criterion 5" is not entirely clear in this context. If it means that criterion 6 only applies if the prices are not those in the approved pricing proposal (on the basis that the terms and conditions are so different …etc), and the AER considers that the situation with which EnergyAustralia is concerned would fall into this category (because the prices or principles are separately regulated), then there could be a conflict between the relevant regulation and the remainder of the pricing criteria. Our new criterion 4A is designed to overcome this conflict.

Thirdly, EnergyAustralia is concerned at the considerable confusion that the negotiable component classification and criteria may cause in network users. EnergyAustralia would hope that the AER would take any opportunity it can to make the framework as clear as possible for those users.

In fact, the AER quotes EnergyAustralia saying that the majority of negotiable components will be in respect of connection and therefore the price will largely be subject to the capital contributions framework. It is difficult to understand therefore why the AER would oppose including EnergyAustralia's provision in the criteria.

5.2 The AER's proposed criteria

The AER's proposed and final NCC and NDSC include the substance of each of the Negotiated Distribution Service Principles and Negotiable Component Criteria Principles in full, except for that set out in clauses 6.7.1(9) and 6.7A.1(10) respectively.

This principle states in full (emphasis added):

> The terms and conditions of access for a negotiated distribution service/ negotiable component should be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the Rules ***(for these purposes, the price for a negotiated distribution service/negotiable component is to be treated as being fair and reasonable if it complies with principles (1) – (7/8) of this clause).***

EnergyAustralia's comments

Excluding 6.7.1(9) and 6.7A.1 (10) from the NCC/NDSC while including all other clauses does not comply with the Rules and creates confusion for negotiating parties

The AER has not included the text in bold and italics above ("the deleted text"). EnergyAustralia submitted that for the criteria to give effect to and be consistent with the relevant principles, it must reinstate the deleted text.

The AER states in its draft determination that the NCC and NDSC are only meant to give effect to and be consistent with the principles set out in clause 6.7.1 and 6.7.A.1. It further states that the AER is required to follow the NER when applying the criteria and therefore it is not necessary to amend the NCC and NDSC as suggested.

EnergyAustralia submits that the AER's decision is incorrect and does not comply with the Rules because removal of the deleted text does not give effect to the principle. Its deletion indicates that the compliance with principles (1)-(7/8) does not, of itself, require a price to be treated as fair and reasonable. On the contrary, it leaves it open for there to be further requirements that must be met for the price to be considered fair and reasonable. This clearly does not give effect to the principle and is not consistent with the principle.

The AER further states that it is required to follow the NER when applying the criteria. While the AER is required to comply with the NER as a general proposition, it is not apparent how this would have any bearing on the application of the principle. Clauses 6.7.4(b) and 6.7A.4 (b) require the NDSC and NCC to give effect to the principles, and it is the NDSC and NCC which then must be applied. There is no other express requirement that the principles should be applied if there is an inconsistency between the principles and the criteria. The relevant principle has a specific purpose and no reasoning has been put forward why it should not apply. In fact, the AER's reasons appear to indicate that it should apply. If this is the case, there it is no reason why it should not be included in the criteria.

The AER's reasons emphasise the importance of consistency with the negotiated service criteria adopted in its previous determination for TNSPs. As indicated in section 5.3 below, the AER should not defer to regulatory precedent for its own sake, particularly where cogent reasons have been put forward as to why it should not be followed.

Furthermore, the deletion has the potential to create confusion for negotiating parties.

5.3 Regulatory precedent

The AER appears to be placing significant weight on its own (limited) regulatory precedent and seems unwilling to deviate from these criteria as they have been applied before.

For example, the AER in its draft determination states that:

> The AER further emphasises the importance of consistency with the negotiated transmission service criteria adopted in its previous determinations for TNSPs.[300]

[300] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, pp31-32.

EnergyAustralia's comments

There is no obligation to be consistent with the approach adopted in previous determinations if cogent reasons have been put forward which justify departure from such an approach

EnergyAustralia has put forward what it considers to be reasonable suggestions for changes to the proposed criteria. The AER's rejection of those suggestions appears to be influenced by a perceived need for consistency with (very limited) regulatory precedent and consistency with the transmission service criteria rather than a proper consideration of the substance of the matters.

EnergyAustralia submits that the AER should be open to suggested changes and improvements to the criteria and should give particular attention to the appropriate criteria for distribution services. These criteria have been required since the introduction of Chapter 6A at the end of November 2006 and have only been determined in the context of two regulatory determinations for transmission businesses. This is insufficient to establish an acceptable regulatory precedent, particularly for distribution.

EnergyAustralia's concerns in this regard are reinforced because the AER has been inconsistent in its reasoning in rejecting EnergyAustralia's suggested changes. For example, in relation to criterion 1, the AER states that it is appropriate to restate that the terms and conditions of access must "promote" the achievement of the national electricity objective. However in the context of criterion 2, the AER has rejected EnergyAustralia's suggestion the criterion should fully (and not partially) reflect the principle contained in clauses 6.7.1 (9) and 6.7A.1(10) that a price for a negotiated distribution service or negotiable component is to be treated as fair and reasonable if it compiles with the principles in subclauses (1)-(7/8).

The AER states in its reasons [301] that:

> The AER is required to follow the NER when applying the criteria and therefore it is not necessary to amend the NCC as suggested in EnergyAustralia's submission.

This reasoning would apply equally to criterion 1 as the AER is required by section 16 of the NEL to perform or exercise an economic regulatory function in a manner that will or is likely to contribute to the achievement of the national electricity objective, but in that case the AER has stated the inclusion of the criteria is appropriate.

EnergyAustralia supports the AER's discretion to amend criteria to meet specific circumstances of each business. If the AER believes a more appropriate approach is to apply a standard set of criteria universally, it should consider raising this issue with the AEMC in the form of a Rule change.

The AER must take into account the different circumstances of negotiating frameworks for distribution businesses

The AER must give proper consideration to the application of the criterion to distribution and to the fact that there is a clear policy intention that the criteria should be developed by the AER as appropriate for each determination; otherwise the criteria would have been codified.

The AER's decision in relation to EnergyAustralia's suggested change to criterion 5 demonstrates that the AER has not given sufficient consideration to the application of the criteria to distribution services.

5.4 EnergyAustralia's proposed changes

The AER notes the importance of NCC and NDSC in negotiating terms and conditions of access between EnergyAustralia and negotiating parties. The AER also notes that the intent of the changes proposed in EnergyAustralia's submission is to remove unnecessary ambiguity from the criteria. This will improve negotiation and dispute outcomes for all parties.

[301] AER, *Draft decision, New South Wales: Draft distribution determination 2009-10 to 2010-14*, November 2008, p31 and p34.

EnergyAustralia's comments

The inclusion of criterion 1 is unclear and ambiguous

EnergyAustralia reiterates its previous submission that including this higher order objective within criteria that are already designed to contribute to the achievement of the objective is unnecessary and creates potential ambiguity in application.

The AER is required by section 16 of the NEL to perform or exercise an AER economic regulatory function in a manner that will or is likely to contribute to the achievement of the national electricity objective. Consequently, the criteria themselves should have been developed in a manner which is likely to contribute to the achievement of the national electricity objective. Putting aside that use of the term "promote" the achievement of the national electricity objective" does not make sense in the context of the national electricity objective, it is not at all apparent how EnergyAustralia or the AER if arbitrating would be able to reflect criterion 1 beyond that which is already reflected in the criteria.

If inclusion of criterion 1 is still kept it is inappropriate to use promotion of the NEO

EnergyAustralia submitted that if criterion 1 is retained it should be made consistent with other references in the NEL so that the requirement is "to contribute to" the achievement of the National Electricity Objective. This is consistent with the obligation upon the AER in section 16 of the NEL and the obligation upon the AEMC in sections 88 and 91A of the NEL.

The inclusion of the requirement "to promote" the achievement of the national electricity objective creates ambiguity in the application of what should otherwise be a straight forward objective. To use a different formulation implies that a different obligation is being imposed, which is not logical or appropriate. The effect of the AER's criterion is that the terms and condition of access "should promote the promotion of the efficient investment in, and efficient operation and use of electricity services." The meaning of such a requirement is not clear and arguably does not make sense at all.

Glossary

A

ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AER	Australian Energy Regulator
AEMC	Australian Energy Market Commission
AIM	Asset and Investment Management
ASP	Accredited Service Provider

C

CAPEX	Capital Expenditure
CAPM	Capital Asset Pricing Model
CBD	Central Business District
CEG	Competition Economics Group
CGS	Commonwealth Government Security
CLR	Commonwealth Law Report
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CRNP	Cost-Reflective Network Pricing
CSV	Cost Scale Variable
CY	Calendar Year

D

DWE	NSW Department of Water and Energy
DM	Demand Management
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DRP	Debt Risk Premium
DRP licence conditions	NSW Design, Reliability and Performance Licence Conditions
DUOS	Distribution Use of System

E

EA	EnergyAustralia
EBSS	Efficiency Benefit Sharing Scheme
EGW	Electricity, Gas and Water
ElectraNet	SA Transmission Network Service Provider
ESC	Essential Services Commission of Victoria

F

FTE	Full Time Equivalent
FY	Financial Year

G

GCSS	Guaranteed Customer Service Standards
GWh	Gigawatt hour

H

Huegin	Huegin Consulting
HV	High Voltage

I

iAMS	integrated Asset Management System
ISSR	Inherent, Structural, Systemic and Realised cost-driver framework
IPART	Independent Pricing and Regulatory Tribunal of NSW

K

KW	Kilowatt (one kW = 1000 watts)
KWh	Kilowatt hour
kV	Kilovolt

L

LME	London Metal Exchange
LNSP	Local Network Service Provider
LV	Low Voltage

M

MCE	Ministerial Council on Energy
M&M	Miscellaneous fees and monopoly services
MMA	McLennan Magasanik Associates
MRP	Market Risk Premium
MW	Megawatt (one MWh = 1000 KWh)
MWh	Megawatt hour

N

NCC	Negotiable Component Criteria
NDSC	Negotiated Distribution Services Criteria
NEL	National Electricity Law

Glossary (continued)

NEO	National Electricity Objective
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
NPV	Net Present Value
NSP	Network Service Provider
NUOS	Network Use of System
O	
Ofgem	Gas and Electricity Market Authority (UK)
O&M	Operating and Maintenance
OMS	Outage Management System
OPEX	Operating Expenditure
P	
PB	Parsons Brinckerhoff Associates
PPI	Producer Price Indices
PTRM	Post Tax Revenue Model
PWC	PriceWaterhouseCoopers
R	
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
RCM	Reliability Centred Management
RFM	Roll Forward Model
RIN	Regulatory Information Notice
S	
SAHA	SAHA International
SAIDI	System Average Interruption Duration Index
SKM	Sinclair Knight Merz
SLUOS	Street Lighting Use of System
SOC	State Owned Corporation
SOO	Statement of Opportunities
ST	Subtransmission
STPIS	Service Target Performance Incentive Scheme
SP AusNet	Publicly listed Victorian Transmission and Distribution provider

T

TNSP	Transmission Network Service Provider
TOU	Time of Use
TransGrid	NSW Transmission Network Service Provider
TUOS	Transmission Use of System

W

WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap

Attachments

Attachments to Part I – Building Block Proposal

Attachment 1A:	Revised Post Tax Revenue Model (PTRM)
Attachment 2A:	Revised Roll Forward Model (RFM)
Attachment 3A:	Impact of Revised Peak Demand Forecast on Area Plans, January 2009
Attachment 3B:	Revised 11kV Distribution Mains Capital Requirements 2009-14, January 2009
Attachment 3C:	Evans & Peck, Impact of Revised Demand Forecasts on Capital Requirements for Distribution Substations and Low Voltage Distribution, 19 December 2008 (with attachment)
Attachment 3D:	Revised Distribution Substation & Low Voltage Network Capital Requirements 2009-10 to 2013-14, January 2009
Attachment 3E:	Revised DM Impact on 2009-2014 Capital Forecasts, January 2009
Attachment 3F:	Material Equipment Contracts Arrangements Demonstrating Lagging Escalator
Attachment 3G:	CEG – Cost Escalation Model
Attachment 3H:	Macromonitor, Forecasts of Labour Indicators for the Electricity Transmission Sector, 29 August 2008
Attachment 3I:	CEG, Escalators Affecting Expenditure Forecasts, 14 January 2009
Attachment 3J:	PWC, Independent Report of CEG Method, 12 January 2009
Attachment 3K:	Response to AER Questions on Escalators and Reliability Targets of 26 September 2008, 3 October 2008
Attachment 3L:	Australia Timber Pole Resources for Energy Networks – A Review, October 2006
Attachment 3M:	SKM, Considerations on AER Review of EnergyAustralia's Substation Cost Estimation Process, 7 January 2009
Attachment 3N:	Joint Industry Association – Debt and Equity Raising Costs, 11 November 2008 (with attachment)
Attachment 3O:	CEG, Debt and equity raising costs – A response to the AER 2008 draft decisions for electricity distribution and transmission, January 2009
Attachment 3P:	Carlton, Indirect Costs of Equity and Debt Raising, 12 January 2009
Attachment 3Q:	EnergyAustralia Revised Cost Escalators
Attachment 7A:	EnergyAustralia's revised depreciation schedule
Attachment 8A:	AER's Decisions to Withhold Agreement, January 2009
Attachment 8B:	CEG, Rate of return and the averaging period under the National Electricity Rules and Law, 14 January 2009
Attachment 8C:	News release issued by the AER on 28 November 2008 entitled 'Regulators Draft decision approves increased investment in NSW electricity distribution network' (Release # MR017/08)
Attachment 9A:	Huegin Consulting Group, EnergyAustralia Regulatory Proposal Review (OPEX), 13 January 2008
Attachment 9B:	EnergyAustralia, Responses to Wilson Cook's questions, 8 August 2008
Attachment 9C:	Concept Economics, Operating efficiencies in periods of high investment and technology change, 9 September 2008
Attachment 9D:	PWC, Case study on operating expenditure efficiencies, 8 January 2009

Attachment 9E:	SKM, Responses to Wilson Cook Commentary on O&M / Age Profile Modelling, 5 January 2009
Attachment 9F:	EnergyAustralia, Responses to Wilson Cook's questions, 15 August 2008
Attachment 9G:	SAHA, Response to the AER's Draft Decision – Self - Insurance, 14 January 2009 (with attachments)
Attachment 13A:	Revised Energy and Global Peak Demand Forecasts to 2014
Attachment 13B:	Oakley Greenwood, Review of Revised Forecasts for EnergyAustralia, 13 January 2009
Attachment 15A:	EnergyAustralia, Response to the AER on self-insurance and pass through, 5 August 2008

Attachments to Part II – Services classification and control mechanism proposal

Attachment II.4A:	EnergyAustralia's Revised Calculation of the Weighted Average Price Cap
Attachment II.4B:	EnergyAustralia WAPC form of price control with growth factor adjustment G
Attachment II.4C:	Miscellaneous Fees and Monopoly Charges – Comparison of revenue outcomes when applying EA v AER proposed rates
Attachment II.4D:	EnergyAustralia letter to the AER dated 1 August 2008
Attachment II.4E:	Applying the Control Mechanism to Miscellaneous and Monopoly Services

Attachments to Part III – Pricing & Negotiating frameworks

Attachment III.4A:	EnergyAustralia Revised Transmission Pricing Methodology

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