ElectraNet

ELECTRANET TRANSMISSION NETWORK
REVISED REVENUE PROPOSAL

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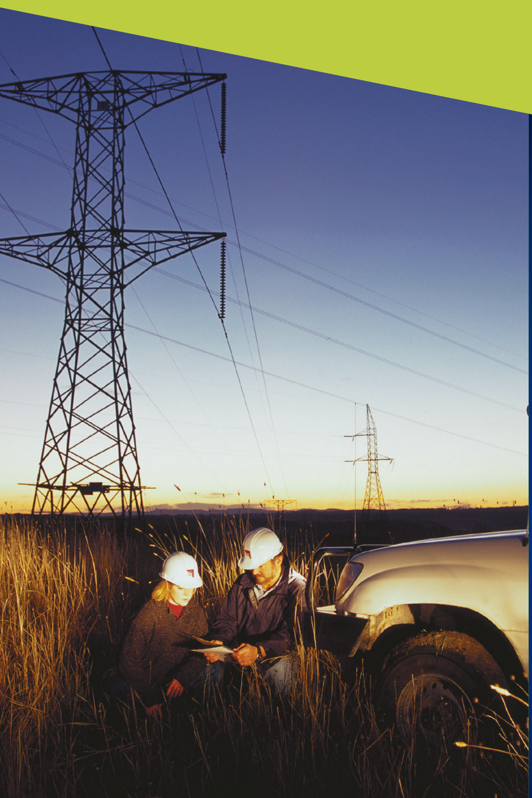

ElectraNet Pty Ltd (ElectraNet) is the principal electricity transmission network service provider (TNSP) in South Australia.

For information about ElectraNet visit www.electranet.com.au.

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1. Overview

1.1 Introduction

ElectraNet Pty Ltd (ElectraNet) is the principal electricity transmission network service provider (TNSP) in South Australia.

On 31 May 2012, ElectraNet submitted a Revenue Proposal to the Australian Energy Regulator (AER) for the regulatory control period from 1 July 2013 to 30 June 2018 in accordance with the National Electricity Rules (Rules). ElectraNet's Revenue Proposal has been the subject of public consultation and detailed review by the AER and its consultants. On 30 November 2012, the AER published a Draft Decision on its transmission determination for ElectraNet (Draft Decision).

This revised Revenue Proposal is submitted by ElectraNet in accordance with Chapter 6A of the Rules.[1]

ElectraNet has carefully reviewed all of the matters raised by the AER in its Draft Decision. In many instances, ElectraNet has incorporated the changes required by the Draft Decision in the revised Revenue Proposal. Where ElectraNet has not fully incorporated a particular aspect of the AER's Draft Decision, the revised Revenue Proposal provides additional information, including independent expert reports, to address the matters raised by the AER and to demonstrate that the revised Revenue Proposal satisfies the requirements of the Rules.

ElectraNet's revised capital expenditure (capex) and operating expenditure (opex) forecasts and revenue requirements reflect ElectraNet's reliability obligations under the South Australian Electricity Transmission Code (ETC). ElectraNet has also proposed amendments to the ETC to formalise the adoption of 10 per cent probability of exceedance demand forecasts as the relevant forecasts for non-radial connection point and regional network planning. These demand forecasts are reflected in the revised forecasts presented in this revised Revenue Proposal, and have the impact of deferring load driven capital investments and minor consequential impacts on maintenance requirements.

ElectraNet submits this revised Revenue Proposal on the basis that the overall revised proposal, and its capex and opex forecasts in particular, reasonably reflect the efficient costs of a prudent operator and are consistent with realistic demand assumptions.

1.2 Revised Forecast

ElectraNet's revised Revenue Proposal sets out a maximum allowed revenue (MAR) requirement that increases from $291.7 million in 2013-14 to $353.3 million in 2017-18 ($nominal) with a total MAR of $1,608.8 million over the next regulatory control period.

By comparison the AER's Draft Decision MAR increases from $259.2 million in 2013-14 to $341.5 million in 2017-18 ($nominal) with a total MAR over the next regulatory control period of $1,511.5 million.

1 ElectraNet's revised Revenue Proposal has been prepared in accordance with Chapter 6A as it was in force at the time of lodgement of ElectraNet's Revenue Proposal on 31 May 2012 as amended by the Rules made by the Australian Energy Market Commission with respect to cost pass through arrangements for network service providers, which commenced on 2 August 2012.

The differences between ElectraNet's revised Revenue Proposal and the Draft Decision essentially arise from ElectraNet's firm belief that the AER's Draft Decision does not provide expenditure allowances that meet the fundamental regulatory requirement of providing ElectraNet with a reasonable opportunity to recover the efficient costs ElectraNet incurs in providing electricity transmission services.

ElectraNet's revised opening regulated asset base (RAB) is $2,087.3 million (as at 1 July 2013). This compares to an opening RAB of $2,077.8 million in the AER's Draft Decision. ElectraNet has incorporated all aspects of the AER's Draft Decision in relation to the opening RAB, with the exception of the AER's treatment of capital provisions. ElectraNet has also included updated forecasts of commissioned assets and assets under construction in the current regulatory control period in establishing its revised opening RAB proposal.

ElectraNet's revised capex forecast for the next regulatory control period is $748.3 million ($2012-13). This compares to $641.9 million in the AER's Draft Decision. ElectraNet has incorporated some aspects of the AER's Draft Decision in relation to forecast capex. However, as set out, in Chapter 6, ElectraNet does not consider that a number of the AER's revisions to the capex forecast are consistent with the requirements of the Rules, the most significant of which relate to:

- cost estimation risk factor;
- prudency adjustment to replacement and refurbishment projects;
- capex / opex trade off adjustment;
- strategic land and easement acquisition costs; and
- deferral of load driven projects.

ElectraNet's revised total opex forecast for the next regulatory control period is $466.2 million ($2012-13). This compares to the $397.6 million in the AER's Draft Decision. Again, ElectraNet has implemented some aspects of the AER's Draft Decision in relation to forecast opex, However, as set out in Chapter 7, ElectraNet does not consider that a number of the AER's revisions to the opex forecast are consistent with the requirements of the Rules, the most significant of which relate to:

- corrective maintenance;
- operational refurbishment;
- network optimisation;
- operating expenditure efficiency factor; and
- real cost escalation

ElectraNet is subject to the AER's service target performance incentive scheme. This scheme encourages TNSPs to improve their service performance levels against measures of network security and reliability (known as parameters). The AER in its Draft Decision made a number of changes to the details of the scheme proposed by ElectraNet. ElectraNet has incorporated all aspects of the AER's Draft Decision in relation to the service target performance incentive scheme with the exception of the AER's proposed weightings on two performance parameters.

ElectraNet estimates that this revised Revenue Proposal would result in a 0.8 per cent per annum nominal increase in average transmission charges from the end of the current regulatory control period. Transmission charges represent less than 10 per cent on average of end user electricity charges in South Australia. ElectraNet estimates that the nominal increase in transmission charges will add approximately $2.21 to the average residential customer's annual bill of $1,481 (0.15 per cent).[2]

The principal drivers affecting transmission revenue over the forthcoming regulatory period are:

- growth in the asset base to meet customer demand, with the revised demand forecasts resulting in significant deferral of capital investment;
- continued implementation of a best practice asset management framework to manage the increased level of network risk revealed through improved asset condition information;
- an increase in the volume of assets nearing the end of their useful lives, requiring increased levels of asset replacement and maintenance expenditure;
- additional investment required to refurbish and extend the life of transmission lines based on asset condition and risk mitigation; and
- increased land and easement acquisition requirements in order to secure land and easements in a timely and prudent manner, to meet emerging transmission line investment needs.

[2] Customer billing data from ESCOSA, *Electricity Annual Performance Report - SA Energy Supply Industry*, November 2012, Statistical Appendix 120410.

2. Introduction

2.1 Background

ElectraNet Pty Ltd (ElectraNet) is the principal electricity transmission network service provider (TNSP) in South Australia.

On 31 May 2012, ElectraNet submitted a Revenue Proposal to the Australian Energy Regulator (AER) for the regulatory control period from 1 July 2013 to 30 June 2018. Under the National Electricity Law and the National Electricity Rules (Rules), the AER is responsible for the economic regulation of electricity transmission services provided by ElectraNet and other transmission network service providers (TNSPs) in the National Electricity Market (NEM).

In making the transmission determination to apply to ElectraNet over the forthcoming regulatory control period, the AER is required to take into account a number of matters, including that the determination should provide ElectraNet with a reasonable opportunity to recover at least the efficient costs ElectraNet incurs in providing electricity transmission services.

ElectraNet's Revenue Proposal has been the subject of detailed review by the AER and its consultants. The AER published ElectraNet's proposal on 5 July 2012 and called for interested parties to make submissions. The AER held a public forum on ElectraNet's proposal on 23 July 2012, where ElectraNet and interested parties made presentations. The AER engaged Electricity Market Consulting associates (EMCa) as a technical expert to advise it on key aspects of the Revenue Proposal.

On 30 November 2012, the AER published its Draft Decision on ElectraNet's Revenue Proposal. The purpose of this revised Revenue Proposal is to provide ElectraNet's response to the AER's Draft Decision.

In addition to ElectraNet's Revenue Proposal, the AER's Draft Decision also considers:

- ElectraNet's proposed negotiating framework for negotiated transmission services;
- ElectraNet's proposed pricing methodology related to the provision of prescribed transmission services; and
- an application from ElectraNet nominating additional cost pass through events for the purposes of the forthcoming regulatory control period, in accordance with a transitional Rule made by the AEMC.

In relation to each of the above matters the AER accepted ElectraNet's proposal, subject to minor drafting changes in relation to the negotiating framework, and the nominated pass through events.

2.2 Approach to Revised Proposal

ElectraNet's revised Revenue Proposal is submitted in accordance with Chapter 6A of the Rules.

ElectraNet has carefully reviewed all of the matters raised by the AER in its Draft Decision. In many instances, ElectraNet has incorporated the changes required by the Draft Decision. Where ElectraNet has not fully incorporated the AER's Draft Decision, the revised Revenue Proposal sets out ElectraNet's response on the particular issue, providing further information where relevant, including expert reports, to address the matters raised by the AER and to demonstrate that the revised Revenue Proposal satisfies the requirements of the Rules.

ElectraNet submits this revised Revenue Proposal on the basis that the overall revised proposal, and its capex and opex forecasts in particular, reasonably reflect the efficient costs of a prudent operator and are consistent with realistic demand assumptions.

This revised Revenue Proposal supplements ElectraNet's Revenue Proposal (May 2012) and makes extensive reference to it and the AER's Draft Decision. Therefore, this revised Proposal should be read in conjunction with those documents.

2.3 Structure of Revised Proposal

The remainder of this revised Revenue Proposal is structured as follows:

- Chapter 3 sets out the real cost escalators used in the capex and opex forecasts;
- Chapter 4 discusses the basis of the updated demand forecast used in developing the load driven capex forecast;
- Chapter 5 discusses ElectraNet's asset management framework;
- Chapter 6 sets out the revised capex forecast;
- Chapter 7 sets out the revised opex forecast;
- Chapter 8 discusses the weighted average cost of capital;
- Chapter 9 discusses the opening regulatory asset base for the next regulatory control period;
- Chapter 10 discusses the revised depreciation allowance;
- Chapter 11 describes the taxation allowance;
- Chapter 12 sets out the maximum allowed revenues for the next regulatory control period;
- Chapter 13 sets out revised values for the service target performance incentive scheme parameters;
- Chapter 14 describes the Efficiency Benefit Sharing Scheme (EBSS) for the current and forthcoming regulatory control period;

- Chapter 15 describes the contingent projects and their triggers;
- Chapter 16 discusses the Pricing Methodology;
- Chapter 17 discusses the Negotiating Framework;
- Chapter 18 addresses the cost pass through events nominated by ElectraNet;
- Chapter 19 provides a Glossary of terms; and
- Chapter 20 provides a listing of Appendices to the revised Revenue Proposal.

3. Real Cost Escalation

3.1 Summary

Chapters 6 and 7 of ElectraNet's Revenue Proposal (May 2012) set out the key inputs and assumptions used to determine the capital and operating expenditure forecasts, including real cost escalators.

The Revenue Proposal set out the costs that a prudent and efficient operator in the circumstances of ElectraNet would incur in the next regulatory control period having regard to the economic outlook in South Australia and more broadly in the medium term, based on the information available at the time the forecasts were prepared.

In relation to ElectraNet's real cost escalators for the 2013-2018 regulatory control period, the AER:

- approved ElectraNet's internal labour cost escalators for the duration of the current Enterprise Agreement (page 61);
- did not approve the use of Electricity Gas Water (EGW) industry data to estimate labour cost escalations for internal labour for the balance of the forecast period, and substituted Electricity, Gas, Water and Waste Services (EGWWS) forecasts developed by Deloitte Access Economics (DAE) unadjusted for productivity (page 59);
- approved the use of the Labour Price Index (LPI) unadjusted for productivity for the construction sector to forecast external labour cost escalation, but substituted alternative forecasts developed by DAE (page 63);
- approved ElectraNet's proposed weighted average material escalation method, but substituted alternative forecasts (page 64);
- approved the method for converting material prices and indices from $US into $AUD, but did not accept the exchange rate forecasts used, and substituted updated forecasts (page 64); and
- did not approve the use of a total land value escalator to land and easement projects and substituted a disaggregated escalator by corresponding land type (page 65).

The substituted forecasts applied by the AER in its Draft Decision reduced ElectraNet's proposed capital and operating expenditure allowances. The most significant driver of the reduction is the substitution of ElectraNet's proposed labour forecasts prepared by BIS Shrapnel (BIS) with the DAE real labour cost forecasts prepared for the AER. DAE's forecasts are presented in an accompanying report prepared for the AER for Victoria and South Australia[3] together with a separate report responding to the forecasts developed for ElectraNet by BIS.[4]

The following sections present ElectraNet's response to a number of issues identified in the AER's Draft Decision. Where necessary, ElectraNet has also provided additional forecast information and analysis for the AER to consider in preparing its Final Decision.

3 *Forecast growth in labour costs: Victoria and South Australia: Report prepared for the AER*, Deloitte Access Economics, 15 October 2012.

4 *Responses to BIS Shrapnel Reports: Australian Energy Regulator,* Deloitte Access Economics, 30 July 2012.

In particular, ElectraNet has secured an expert opinion from KPMG to examine the methodology used by DAE to prepare the AER's substituted labour escalation forecasts,[5] and to prepare a revised set of forecasts addressing the issues raised by the AER and DAE over the original forecasts prepared for ElectraNet by BIS.[6]

The KPMG forecasts follow a similar methodology to the forecasts developed by BIS Shrapnel incorporated in ElectraNet's Revenue Proposal. ElectraNet considers that this reinforces the appropriateness of the forecasts that were contained in ElectraNet's Revenue Proposal. ElectraNet has incorporated the forecasts developed by KPMG in this revised Revenue Proposal as they are based on more recent information and therefore also address the concern of the AER that there had been a material change in circumstances since ElectraNet's proposed external labour cost escalators were produced and that ElectraNet's proposed escalators should be amended to reflect this change.

3.2 Labour cost escalators

3.2.1 Use of labour force industries

AER Draft Decision

As noted above, the AER accepted ElectraNet's internal labour cost escalators for the duration of the current Enterprise Agreement (EA). However, the AER did not accept ElectraNet's proposed labour cost escalation rates for labour costs that were not subject to the EA.

ElectraNet's cost escalation rates were based on BIS Shrapnel forecasts for the Electricity Gas Water (EGW) industry, rather than the EGWWS industry that includes waste services.

The AER concluded that BIS Shrapnel's reasons for excluding the waste service component (that it would result in a lower wage growth) are not sufficient to adjust the EGWWS data. In the AER's view, removing the waste services component from the data introduces a potential source of forecasting error. In addition, the AER argued that forecasting errors were likely to arise if the discontinued EGW industry data series were used for forecasting purposes.

Consequently, the AER concluded that, where applicable, using forecasts of the EGWWS data series as prepared by DAE better reflects a realistic expectation of ElectraNet's future cost movements.

It is noted that a South Australian (SA) utilities (EGWWS) LPI series is not available from the ABS. Therefore, DAE based its forecasts on an historic LPI data series constructed by DAE. The historical series was constructed using AWOTE data to account for the relative movements in labour costs in the EGWWS industries and the average labour costs in South Australia.[7]

5 Appendix C, KPMG, *Independent examination of Labour Cost Escalation modelling used by the AER in ElectraNet's 2012 Draft Decision*, January 2013.
6 Appendix D, KPMG, "*Labour Cost Escalators: Final Report to ElectraNet",* January 2013.
7 DAE, *"Forecast Growth in Labour Costs: Victoria and South. Australia,"* 15 October 2012, page 111.

ElectraNet's Response

ElectraNet does not agree that the use of the EGWWS industry sector as a measure of future labour costs reasonably reflects a realistic expectation of ElectraNet's labour costs for its internal labour for the 2013-2018 regulatory control period.

While all job classifications within the wider EGWWS service contribute to the measure, as noted by the AER based on advice from the ABS,[8] ElectraNet operates only within the electricity transmission sector. The incorporation of waste services data in the labour cost index cannot improve its relevance to ElectraNet. On the contrary, it lessens its relevance because ElectraNet's labour requirements and associated costs are materially different to those of the waste services sector.

ElectraNet has sought an independent expert opinion from KPMG on the appropriate index (EGW or EGWWS) to apply to most accurately represent the circumstances of ElectraNet for the period 2012-13 to 2017-18. The KPMG report concludes that as ElectraNet is an electricity transmission business and does not operate in waste services, EGW is a more appropriate index than EGWWS to apply to the circumstances of ElectraNet.[9] The KPMG report is provided as Appendix D.

As KPMG observes:[10]

> 'If the utilities' LPI movements are heavily influenced by large scale projects in non-electricity sectors (for example, the development of a large scale desalination plant), it may not accurately forecast electricity sector wage cost growth. From this point of view, LPI forecasts for a sub-set of utilities sector would be more accurate than those for the whole utilities sector.'

Significantly KPMG noted that according to the most recently published ABS input-output tables for 2008-09 (ABS 5209.0.55.001), the WS industry is highly labour-intensive compared to the EGW industries. The following table shows the wage cost shares of output for the four sub-sectors of utilities.[11]

Table 3-1: Wage Cost Share of Output Utilities Sub-sectors

	Electricity	Gas	Water	Waste
Compensation of employees ($m)	5,259	185	2,492	1,800
Output ($m)	39,503	2,386	14,298	3,345
Wage share of output (%)	13.3	7.8	17.4	53.8

The dominant wage share of waste services means that its inclusion in the utility LPI provides an unreasonable bias in the wage escalation forecast for the electricity sector.

ElectraNet notes that the AER in the Powerlink final decision (April 2012), agreed that EGW would be preferable to EGWWS (page 60) although expressed a concern in deriving EGW LPI due to the unavailability of EGW LPI series from ABS since late 2009.

8 AER, Draft Decision page 58.
9 KPMG, Appendix C, Independent examination of Labour Cost Escalation modelling, page 5.
10 KPMG, Appendix C, Independent examination of Labour Cost Escalation modelling, page 5.
11 KPMG, Appendix C, Independent examination of Labour Cost Escalation modelling, page 18.

ElectraNet acknowledges that in separating out the electricity industry or waste service industry from the utility sector, there may be issues with the sampling becoming too small and therefore being affected by outliers. However, if the industry composition of the utility sector is stable, such small sampling issues may be satisfactorily addressed. In particular, KPMG advises that the EGW sector LPI can be derived from EGWWS LPI by applying a systematic approach to isolating waste service components.[12]

Therefore, based on KPMG's assessment, ElectraNet proposes that the EGW LPI be used because the entire EGWWS LPI tends to provide a bias when assessing wage escalation for the electricity sector. The removal of the bias is desirable, especially as KPMG removes the waste service in a systematic and statistically robust way, and the benefits of this approach in improving the accuracy of the measure outweigh any minor statistical error introduced through this adjustment.[13]

ElectraNet notes the following other concerns with DAE's approach:

- DAE's estimation of the South Australian LPI historical series relies on the published AWOTE series; and
- the AWOTE series is highly volatile, and DAE's reliance on AWOTE data will therefore infect the constructed LPI series and the resulting forecasts. In fact, in its responses to BIS Shrapnel in July 2012 DAE had rejected the use of the AWOTE series because of its volatility. Furthermore, the AWOTE series has not been available since late 2011. It is therefore inconsistent and inappropriate to employ the AWOTE series for the purposes of constructing the LPI data series as it introduces potential measurement errors to the LPI estimates.

DAE explicitly recognises the difficulties associated with the ABS' AWOTE measures stating the following:

> "The ABS has reviewed its production of AWE and AWOTE measures at the industry by State level (that is, the AWOTE for the utilities sector in Victoria). This information will now no longer be produced.
>
> A key reason was the high standard errors for these series. In the case of the AWE / AWOTE publication, sample selection is stratified across States and across industries, but not both. That means that as the businesses in the sample change from quarter to quarter (and about 8 per cent of the 5,000 do each time) there is no guarantee that the State by industry samples can be readily compared. This led to questionable comparability of detailed AWE / AWOTE results from quarter to quarter as the changes may be driven by changes in the sample, rather than changes in wages."[14]

On the basis of the findings of the KPMG report, ElectraNet has not incorporated DAE's EGWWS LPI series for South Australia in its revised Revenue Proposal as ElectraNet does not consider that this series provides a realistic expectation of the cost inputs required to achieve the operating and capital expenditure objectives.

With respect to the AER's concerns regarding ElectraNet's proposed adoption of BIS Shrapnel's EGW LPI forecasts, KPMG's independent expert opinion is that BIS Shrapnel's EGW LPI forecasts would provide more accurate forecasts than DAE's EGWWS LPI forecasts. Furthermore, KPMG noted.[15]

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12 KPMG, Appendix C, Independent examination of Labour Cost Escalation modelling, page 18.
13 KPMG, Appendix C, Independent examination of Labour Cost Escalation modelling, page 18.
14 KPMG, Appendix C, Independent examination of Labour Cost Escalation modelling, page 9.
15 KPMG, Independent examination of Labour Cost Escalation modelling, page 5.

> "The AER expressed in its Draft Decision its concern with the potential forecasting errors in BIS Shrapnel's EGW LPI when removing the Waste Services (WS) components from EGWWS LPI (see page 59 in AER's Draft Decision). However, if the compositional mix of sub-sectors within the entire utilities sector is stable, the derivation of the EGW components from the entire utilities LPI may be developed in a robust way, for example using the Census data published by ABS. If a robust approach to disaggregating the utilities LPI into its sub-sector components is available, the LPI forecasts for the more narrowly defined utilities sub-sector would increase accuracy in forecasting wage cost growth in the electricity industries. From this point of view, the accuracy of DAE's SA utilities LPI forecasts could be further improved."

ElectraNet concurs with KPMG's views that the better approach is to construct an LPI series that excludes waste services. Furthermore, the Rules require the AER to provide expenditure allowances that reasonably reflect ElectraNet's efficient costs. In order to satisfy this requirement, labour costs in the waste sector are not relevant and should be disregarded.

Consistent with the view of BIS Shrapnel, KPMG found that the inclusion of the waste services sub-sector in the classification resulted in lower wage outcomes as shown in Table 3-2 below.

Table 3-2: LPI Forecast EGW and EGWWS (per cent p.a. Nominal) – KPMG[16]

	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
EGW	5.1	4.8	4.3	4.6	4.9	4.9
EGWWS	4.7	2.6	3.9	4.3	4.6	4.6

In light of KPMG's independent expert opinion, the EGW outlook is more reflective of the business environment within which ElectraNet operates. The alternative forecast developed by DAE is inconsistent with the Rules requirements because:

- the method of constructing the index is unreliable because it relies on the use of the AWOTE data series which is inherently volatile; and
- the inclusion of waste services labour cost data does not provide a reasonable basis for forecasting ElectraNet's costs, as illustrated in the forecasts produced by BIS Shrapnel and KPMG.

KPMG's forecast approach does not rely on any movements of historically available AWOTE which is defined differently in the sampling process and is also intrinsically volatile. KPMG's approach entirely utilises the published LPI measures to estimate the missing LPI for utilities (EGWWS) in QLD, SA, WA, TAS, NT and ACT by establishing systematic relationships between underlying LPI components of each state/territory and the published national level utility LPI.[17]

KPMG acknowledges that similar to DAE's estimates of SA utility LPI, its approach may also be subject to statistical errors.

However, the potential statistical errors in KPMG's approach are substantially reduced because KPMG's approach is based on internally consistent relations of the published LPI series rather than using other indicators of the wage movements.

16 Appendix D, KPMG, Independent examination of Labour Cost Escalation modelling, page 9.
17 Appendix C, KPMG, Independent examination of Labour Cost Escalation modelling, page 15.

For example, DAE uses AWOTE to estimate the LPI which are not published by ABS. As the DAE report to the AER itself discussed (page 109), the volatility of AWOTE is one of the main reasons why the ABS developed the new LPI measure.[18]

The National Electricity Law requires that ElectraNet should be provided with a reasonable opportunity to recover at least its efficient costs. In ElectraNet's view, the AER's Draft Decision does not satisfy this requirement. ElectraNet therefore proposes that the LPI EGW forecasts calculated by KPMG should be adopted as a reasonable reflection of its realistic costs.

3.2.2 Forecast Assumptions

AER Draft Decision

The AER believes there has been a material change in circumstances largely due to the deferral of the Olympic Dam project since BIS Shrapnel's labour costs forecast was produced and the Revenue Proposal needs to be amended to reflect this change.

As a consequence of the uncertainty associated with the commencement of the Olympic Dam project, the AER considers BIS Shrapnel's forecast does not reasonably reflect a realistic expectation of cost inputs required to achieve the operating and capital expenditure objectives over the 2013–2018 regulatory control period.

The AER considers DAE's forecast to be a more accurate forecast of future labour costs required to achieve the operating and capital expenditure objectives over the 2013-2018 regulatory control period.

DAE in its report for the AER forecast that utilities' (EGWWS) LPI would grow on average at a rate lower than the all-industry LPI growth forecast.[19] DAE concluded that utilities' wage growth cannot maintain historically higher growth compared to national wage growth in the medium and long term and that the utilities' wage growth will eventually be similar to or lower than national average growth.[20]

DAE concluded that the convergence between utilities' wage growth and national average LPI growth from mid-2009 reflects the following:

- a degree of unwinding of the utilities sector's previous high wage gains; and
- the electricity sector's recent sharp contraction in output.

DAE utilities' LPI forecast assumed that utilities' sector growth will be lower than the national average growth rate within the near term and for the remainder of the next regulatory control period.

18 KPMG, Independent examination of Labour Cost Escalation modelling, page 15.
19 DAE, "*Responses to BIS Shrapnel Reports - AER*," 30 July 2012, page 14-16.
20 DAE, "*Responses to BIS Shrapnel Reports - AER*," 30 July 2012, page 14-16.

ElectraNet's Response

ElectraNet does not accept the forecast prepared by DAE is a realistic expectation of ElectraNet's future labour costs.

ElectraNet notes that the BIS' forecast was prepared prior to BHP's announcement of the deferral of the Olympic Dam expansion and acknowledges that the South Australian environment has potentially changed from the time of the Revenue Proposal submission.

As noted above, ElectraNet therefore engaged independent expert KPMG to revisit ElectraNet's forecast labour cost escalators for the next regulatory control period in light of the changed environment and the matters raised in the Draft Decision.

Based on KPMG's analysis, ElectraNet does not believe that the recent postponement of the Olympic Dam project will lower the wage growth outlook in the SA utilities sector to the extent set out in the DAE forecast.

DAE contends that an industry LPI can not continue to grow faster than the all-industry or national average.[21] However, as noted by KPMG, there is no statistical evidence that wage growth across industries is converging to the national average since the publication of the LPI in September 1997.[22]

The utilities sector has persistently shown LPI growth higher than the national average for the past 15 years. KPMG notes that if a convergence mechanism operates in the labour market as DAE indicates in its current and previous reports to AER, it is hard to justify why unwinding movements have not occurred over the past 15 or 20 years. KPMG explains that the persistent above-average LPI growth pattern in the past 15 years may reflect particular characteristics of the utilities' sector that are unlikely to change, such as the different compositional mix of occupations.[23]

More generally, KPMG explains that wage growth imbalances in the Australian economy adjust toward equalisation slowly. This reflects to a large extent the low level of labour mobility across states, which implies labour market imbalances are not removed efficiently.[24]

Wage growth differentials can persist due to a number of factors including;[25]

- inherent location specific premiums in terms of both wage levels and growth;
- inherent occupation specific premiums in terms of both wage levels and growth; and
- inherent human capital specific premiums in terms of both wage levels and growth.

KPMG noted that activity in the electricity, gas, water and waste services in Australia has slowed down from recent high levels, but is expected to stabilise around trend growth within the forecast horizon[26]. More broadly, the Gross State Product (GSP) growth outlook for resource rich states such as South Australia should remain above the national outlook.[27]

21 DAE, "Responses to BIS Shrapnel Reports - AER," 30 July 2012, pages 49, 50.
22 Appendix C, KPMG, Independent examination of Labour Cost Escalation modelling, page 4.
23 Appendix C, KPMG, Independent examination of Labour Cost Escalation modelling, page 8.
24 Appendix C, KPMG, Independent examination of Labour Cost Escalation modelling, page 8.
25 Appendix C, KPMG, Independent examination of Labour Cost Escalation modelling, page 8.
26 Appendix C, KPMG, Independent examination of Labour Cost Escalation modelling, page 4.
27 Appendix C, KPMG, Independent examination of Labour Cost Escalation modelling, page 15.

Therefore it is expected output growth for the utilities sector will remain strong as KPMG notes, and as supported by evidence from the ABS:[28]

> "GVA [Gross Value Added] in Australian EGWWS has been highly volatile and the last 'cycle' of activity peaked in 2009 on the back of high investments encouraged by deregulation and a move into renewable energy. Activity slipped off its peak and the industry contracted in three quarters in 2011 and 2012. The industry is nevertheless on a path to recovery and our projected growth is in line with the historical average. The firm outlook is supported by a recent pick-up in national investments in electricity generation, transmission and distribution."[29]

Given that the SA outlook is expected to remain strong, there is an expectation that GVA in the utilities sector will have a positive trajectory over the forecast period which will apply upward pressure on wage costs as noted in the previous section.

In view of the foregoing issues, KPMG has therefore concluded that the flaws in the methodology applied in the construction of DAE's forecasts:[30]

- undermine their likely robustness for forecasting the LPI for ElectraNet; and
- suggest that they may underestimate likely wage pressures in the South Australian electricity sector and, therefore, the forecasts of costs likely to be experienced by ElectraNet over the forecast period.

ElectraNet therefore does not accept that the forecast prepared by DAE provide a realistic expectation of ElectraNet's future labour costs, and has applied the labour cost escalation forecast developed by KPMG.

3.2.3 Adjusted versus unadjusted productivity forecasts

AER Draft Decision

The AER concluded in its Draft Decision that productivity adjustments should not be applied to real labour cost escalations. The AER noted that, in theory, productivity adjustments should be applied to real cost escalations if productivity adjustments are not undertaken elsewhere in the operating and capital expenditure forecasts. However, the high degree of difficulty in estimating quality adjusted labour productivity estimates does not give the AER the ability to make this adjustment with an appropriate level of certainty.[31]

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28 Appendix C, KPMG, Independent examination of Labour Cost Escalation modelling, page 15. ABS, *"Catalogue 8760 – Engineering Construction Activity,"* Australia, released 3 October 2012.

29 KPMG, Appendix D. *"Labour Cost Escalators* page 15, ABS, *"Catalogue 8760 – Engineering Construction Activity,"* Australia, released 3 October 2012.

30 Appendix C, KPMG, "Independent examination of Labour Cost Escalation modelling used by the AER in ElectraNet's 2012 Draft Decision" December 2012, page 6.

31 AER, "Draft Decision ElectraNet Transmission Determination 2013-14 to 2017-18," November 2012, page 60.

ElectraNet's Response

ElectraNet agrees that productivity adjustments should not be applied to real labour cost escalation and has not included such adjustments in its revised Revenue Proposal. BIS noted that the application of more general productivity measures such as output to employment productivity for an electricity network business are largely impractical.[32] Furthermore, CEG explained that the building block approach already accounts for productivity improvements that are derived from output growth, and consequently a further productivity adjustment to labour costs would amount to double counting.[33] For these reasons ElectraNet concurs with the AER's Draft Decision that adjustments to reflect forecast productivity improvements are not appropriate. In particular, such adjustments would not provide ElectraNet a reasonable opportunity to recover its efficient costs in accordance with the revenue and pricing principles in the National Electricity Law.

3.2.4 Use of Negotiated Wage Rate Agreements

AER Draft Decision

The AER noted concerns with the use of EAs to determine real cost escalation as it may not reasonably reflect a realistic expectation of cost inputs. The AER tested whether ElectraNet's EA is reflective of efficient and prudent costs including;

- considering ElectraNet's historical collective wage agreements;
- testing ElectraNet's EA against the expert forecasts; and
- testing ElectraNet's EA against the market.

Following this investigation, the AER was satisfied that there is evidence to support ElectraNet's contention that its existing EA is a realistic expectation of cost inputs required to achieve the operating and capital expenditure objectives.

The AER approved the use of ElectraNet's current EA to escalate internal labour costs until it expires in June 2015.[34]

The AER also included in the approved forecast the expected increase in real labour costs over the period of ElectraNet's current EA as a result of the legislated changes to the superannuation guarantee contribution rate, as proposed by ElectraNet.

ElectraNet's Response

ElectraNet agrees with the decision of the AER with regard to the application of the current EA escalators to internal labour costs, including the impacts of the legislated superannuation contribution guarantee rate (noting that negotiations for the agreement were conducted prior to the changes in the *Superannuation Guarantee (Administration) Act 1992* (Cth) and therefore additional superannuation contributions were not factored into the agreed wage outcomes).

ElectraNet acknowledges that future costs beyond the current EA agreement are expected to be absorbed in agreed wage outcomes, and accordingly no further costs have been factored into the forecast following the expiry of the existing EA in June 2015.

32 BIS Shrapnel, *"Labour Cost Escalation Forecasts to 2017-18 – Australia and South. Australia,"* April 2012, page 46.
33 CEG, *"Escalation factors affecting expenditure forecasts,"* May 2012, paragraphs 46-48.
34 AER, Draft Decision, page 60.

For completeness, ElectraNet does not agree with the AER's forecast internal labour escalators for the remainder of the new regulatory control period, as set out previously in Sections 3.2.1 and 3.2.2. Therefore, in this revised Revenue Proposal, ElectraNet has adopted the South Australian EGW sector forecast prepared by KPMG and shown in Table 3-2, as being representative of ElectraNet's internal real labour costs for the remainder of the next regulatory period beyond the term of the current EA which expires in June 2015.

3.2.5 External labour cost escalation

AER Draft Decision

The AER accepted ElectraNet's proposed approach to escalating external labour costs. However, the AER did not accept ElectraNet's proposed escalators applied to external labour.

As noted above, the AER is of the opinion that BIS Shrapnel's forecast does not reasonably reflect a realistic expectation of cost expectations for the 2013-2018 regulatory control period. This is largely due to the recent postponement of the Olympic Dam expansion in late 2012 not being reflected in BIS' forecast assumptions.

The AER considers DAE's forecast of LPI unadjusted for productivity for the South Australian construction industry to be an appropriate forecast. The AER finds that because DAE's construction wages growth forecast for South Australia does not include the expansion of the Olympic Dam mine it therefore reasonably reflects a realistic expectation of future cost inputs.

DAE argued that for the near term, good growth in the construction sector is expected to see construction LPI grow faster than the national average. However, as capital expenditure peaks in the engineering and construction sectors, the overall construction LPI will grow below the national average LPI.

ElectraNet's Response

ElectraNet does not agree that the AER's external labour forecast applied for the next regulatory control period is a realistic expectation of ElectraNet's external labour costs.

In determining a construction LPI growth forecast, KPMG noted that DAE's assessment is heavily influenced by output growth outlooks (i.e. postponement of Olympic Dam). However, KPMG's analysis suggests that LPI growth is not highly correlated to output growth.[35] This indicates that interactions between the demand and supply of labour with external factors driving one or the other are stronger drivers of LPI growth than the output growth outlook.[36]

Therefore, ElectraNet considers that the recent postponement of the Olympic Dam project is not expected to have the significant downward impact on future cost inputs reflected in DAE's forecast. Significantly KPMG noted that key drivers of the LPI forecast are still likely to be strong for South Australia including:[37]

- performance in the construction sector is pushing demand for construction labour higher, increasing the industry's LPI;

35 Appendix C, KPMG, Independent examination of Labour Cost Escalation modelling, page 11.
36 Appendix C, KPMG, Independent examination of Labour Cost Escalation modelling, page 11.
37 Appendix D, KPMG, *"Labour Cost Escalators* pages 27-29.

- employment in the construction sector has been contracting for four quarters, but is projected to start improving largely due to a firmer economy, easier access to finance and lower interest rates;
- the growth outlook for GSP is likely to be on the upside of the national outlook for resource rich economies like South Australia's; and
- after lower inflation earlier in 2012, price pressures are projected to pick up supported by a moderately weaker exchange rate adding to imported inflation and ongoing price pressures particularly in the mining states of Queensland and Western Australia.

In consideration of the factors above and in response to the concerns raised by the AER over its original forecasts, ElectraNet has adopted KPMG's forecast for the South Australian construction industry for the purposes of its revised Revenue Proposal as being representative of ElectraNet's external real labour cost forecasts for the next regulatory period presented in Table 3-3 below.

Table 3-3: LPI forecast for Construction in SA (per cent p.a. Nominal) - KPMG

	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
Construction	5.0	4.9	6.2	5.5	5.0	5.0

3.3 Material escalators

3.3.1 Weighted average material escalators

AER Draft Decision

In the Draft Decision the AER approved ElectraNet's proposed weighted average materials escalator method.[38] However, the AER substituted forecast inputs for the latest available data and conversion rates.[39] The Draft Decision noted that the AER will again update these inputs further in preparing the Final Decision in 2013.[40]

ElectraNet's Response

ElectraNet has not made any revisions to the weighted average material escalator method it used in its Revenue Proposal. ElectraNet has also engaged an independent expert (CEG) to update ElectraNet's materials forecast with the latest available data, as set out in Table 3-4 below. A copy of CEG's updated independent expert report is included in Appendix E.

38 AER, Draft Decision, page 63.
39 AER, Draft Decision, page 64.
40 AER, Draft Decision, page 64.

Table 3-4: Revised Materials Forecast (% p.a. Real)

	2013-14	2014-15	2015-16	2016-17	2017-18
Aluminium	6.9	4.4	3.4	3.0	2.7
Copper	1.7	0.3	-2.6	-3.6	-4.0
Steel	2.8	3.1	0.8	0.8	0.5
Crude Oil	1.0	-0.9	-1.4	-0.9	-0.6
Construction	-0.1	0.4	0.4	0.1	0.1

3.3.2 Foreign exchange rate forecasts

AER Draft Decision

The AER accepted ElectraNet's use of forward exchange rates to convert the US dollar denominated price inputs for materials escalation to Australian dollars.[41] Given the difficulty in forecasting exchange rates, the AER considered the use of forward exchange rates will produce a realistic expectation of materials costs. In the Draft Decision the AER updated ElectraNet's forecast inputs for the latest available data and conversion rates.[42]

ElectraNet's Response

ElectraNet agrees with the approach adopted by the AER in the Draft Decision. ElectraNet engaged an independent expert (CEG) to update ElectraNet's forecast with the latest available conversion rates which have been reflected in ElectraNet's revised weighted average material annual escalation forecast presented in the previous section. Table 3-5 below shows the revised exchange rate forecast.

Table 3-5: USD/AUD Forecast Average Exchange Rate

	2013-14	2014-15	2015-16	2016-17	2017-18
USD/AUD Exchange Rate	1.014	0.986	0.957	0.931	0.907

3.4 Land value escalation

AER Draft Decision

In the Draft Decision the AER approved ElectraNet's proposed singular land value escalator (total land) be applied as an input to the weighted average material escalator.[43] However, the AER did not accept ElectraNet's proposed total land value escalator be applied as the sole escalator to its proposed forecast land and easement capital expenditure and land tax model.[44] The AER considered that ElectraNet's methodology did not reasonably reflect a realistic expectation of the cost inputs required to achieve the proposed operating and capital expenditure objectives.[45]

41 AER, Draft Decision, page 64.
42 AER, Draft Decision, pages 64-65.
43 AER, Draft Decision, page 65.
44 AER, Draft Decision, page 65.
45 AER, Draft Decision, page 65.

The AER was of the opinion that the application of a total land value escalator to all forecast land and easement capital expenditure is not appropriate as it has the potential to overstate some future land and easement project capital expenditure and land taxes and understate others.[46] The AER noted that the data is available to escalate ElectraNet's proposed land and easement projects by a corresponding land type value escalator because the project locations and land types are known and therefore the relative land type value escalator should be applied.[47]

ElectraNet's Response

ElectraNet has revised its forecasts to incorporate the required revision in the Draft Decision that proposed land and easement projects be escalated by a corresponding land type value escalator. ElectraNet confirms that the land value escalation inputs and assumptions described in the AER's Draft Determination have been reflected in the approach used to revise ElectraNet's proposed operating and capital expenditure forecasts.

3.5 Revised real cost escalators

The AER's Draft Decision was to not approve ElectraNet's proposed cost escalators as the AER did not consider that they reasonably reflected a realistic expectation of cost inputs required to achieve the operating and capital expenditure objectives. The AER's substitute escalators as set out in the Draft Decision are summarised in Table 3-6 below:

Table 3-6 AER's Real Cost Escalation Forecasts (per cent)

	2013-14	2014-15	2015-16	2016-17	2017-18
Internal labour	2.0	2.0	0.7	0.7	1.0
External labour	1.7	1.1	0.6	0.2	0.5
Residential land	8.1	8.1	8.1	8.1	8.1
Commercial land	5.4	5.4	5.4	5.4	5.4
Rural land	4.9	4.9	4.9	4.9	4.9
Other land	5.9	5.9	5.9	5.9	5.9
Total land	6.9	6.9	6.9	6.9	6.9
Aluminium	6.5	4.8	6.5	6.9	1.1
Copper	1.4	0.0	-3.8	-8.7	-3.2
Steel	5.0	-1.1	-1.1	3.8	3.9
Crude Oil	0.1	-3.1	-2.4	-1.6	-1.8
Construction	0.5	0.2	-0.1	0.0	0.0
Weighted Average	2.2	1.2	0.3	0.6	0.9

46 AER, Draft Decision, page 65.
47 AER, Draft Decision, page 65.

As described in the previous sections, ElectraNet considers the escalators proposed by the AER in its Draft Decision do not constitute a realistic expectation of the cost inputs required to achieve the operating and capital expenditure objectives. ElectraNet's updated real cost escalators are provided in Table 3-7 below.

Table 3-7: ElectraNet's Revised Real Cost Escalation Forecasts (per cent)

	2013-14	2014-15	2015-16	2016-17	2017-18
Internal labour	2	2	2.1	2.4	2.4
External labour	2.4	3.7	3	2.5	2.5
Residential land	8.1	8.1	8.1	8.1	8.1
Commercial land	5.4	5.4	5.4	5.4	5.4
Rural land	4.9	4.9	4.9	4.9	4.9
Other land	5.9	5.9	5.9	5.9	5.9
Total land	6.9	6.9	6.9	6.9	6.9
Aluminium	6.9	4.4	3.4	3	2.7
Copper	1.7	0.3	-2.6	-3.6	-4
Steel	2.8	3.1	0.8	0.8	0.5
Crude Oil	1	-0.9	-1.4	-0.9	-0.6
Construction	-0.1	0.4	0.4	0.1	0.1
Compounded Weighted Average	1.0	3.3	5.2	7.0	8.8

ElectraNet considers that its revised real cost escalators establish costs that are both efficient and prudent, based on a methodology that is transparent, independently sourced and robust. These escalators provide a realistic expectation of the reasonable cost inputs required to achieve the operating and capital expenditure objectives over the next regulatory control period.

4. Demand Forecast

4.1 Summary

Chapter 5 of ElectraNet's Revenue Proposal (May 2012) set out the demand forecasts for the next regulatory control period used in determining the load-driven capex forecast. The demand forecasts in the Revenue Proposal comprised demand forecasts independently provided by AEMO, SA Power Networks and ElectraNet's direct connect customers.

In its Draft Decision, the AER did not consider that ElectraNet's proposed load-driven capex forecast reasonably reflected a realistic expectation of the demand forecast required to achieve the capital expenditure objectives.[48]

The AER therefore included a substitute capex forecast in its Draft Decision based on a substitute demand forecast. This substitute forecast resulted in a $103.7 million ($2012-13) reduction in load driven capex.[49]

The AER concluded that the method used to produce ElectraNet's demand forecast:[50]

- did not appropriately consider the uncertainty of temperature fluctuations on peak demand;
- did not appropriately account for photovoltaic generation, embedded generation, and demand response;
- did not apply a diversity factor when modelling regional forecasts; and
- was not reconciled to a top down econometric forecast.

Further, the AER considered that SA Power Networks' peak demand forecasting method was flawed because:

- the 'peak to peak' model is compromised by material adjustments made by SA Power Networks to the historical data it used to extrapolate its demand forecasts (page 77); and
- the extrapolation model did not appropriately consider the underlying growth trend present in the historical demand data (page 78).

In addition, the AER questioned the role of the South Australian Electricity Transmission Code (ETC) in the preparation of the capex forecast and concluded that:

- ElectraNet's obligation under the ETC is to 'react to a change in the forecast agreed maximum demand (FAMD)' and that this is not an obligation to accept FAMD as presented to it by SA Power Networks (page 25);
- ElectraNet's obligations under the ETC are regulatory obligations but they are not 'applicable regulatory obligations' under the capital expenditure objectives of the Rules (page 26); and

48 AER, Draft Decision, page 133.
49 AER, Draft Decision, pages 110, 133.
50 AER, Draft Decision, page 75.

- ElectraNet is not required by any obligation in the ETC to develop a demand forecast. The AER considered that the FAMD is merely a definition of an 'agreed' level of demand and that ElectraNet should negotiate with SA Power Networks to reach such agreement (page 26).

ElectraNet has revised the demand forecast used to determine the load-driven capex forecast in light of a number of matters summarised below, including:

- new information on the future demand outlook in South Australia that became available subsequent to the submission of ElectraNet's Revenue Proposal to the AER; and
- significant work ElectraNet has undertaken in conjunction with AEMO and SA Power Networks on methodologies for forecasting demand.

AEMO has introduced a new demand forecasting methodology that differs from that used by AEMO in the preparation of previous forecasts and, in June 2012, published new national demand forecasts, including for South Australia. These forecasts are materially lower than those which had been forecast in previous years.

ElectraNet has undertaken a significant amount of work since AEMO published its June 2012 demand forecasts, in consultation with AEMO and SA Power Networks to better understand AEMO's new forecasting methodology and its 2012 forecasts. In particular, ElectraNet has put considerable effort into understanding how AEMO's forecast methodology compares to the forecasting methodology used by SA Power Networks to derive the peak demand forecasts that ElectraNet has used for connection point and regional network planning in its Revenue Proposal.

In light of the work ElectraNet has undertaken with AEMO and SA Power Networks, ElectraNet intends to adopt a revised demand forecast based on a 10 per cent probability of exceedance methodology.

ElectraNet has proposed a change to the South Australian Electricity Transmission Code (ETC) to ESCOSA to enable this to occur.[51] Should this change not be approved, or result in more onerous demand forecasting obligations, ElectraNet has also proposed appropriate remedies in its revised Revenue Proposal to address this risk.

ElectraNet considers that the approach it has taken in the revised Revenue Proposal to demand forecasts incorporates the substance of any changes required by the AER's Draft Decision.

ElectraNet's response addressing each of the matters raised in the AER's Draft Decision is set out below, together with a revised demand forecast for inclusion in the AER's Final Decision. Accordingly, the remainder of this Chapter covers:

- response to matters raised in the Draft Decision;
- ElectraNet's 2012 revised demand forecast; and
- a discussion of the obligations under the South Australian Electricity Transmission Code.

[51] Proposed Amendments to the Electricity Transmission Code, ElectraNet, 26 November 2012, http://www.escosa.sa.gov.au/projects/190/electranet-s-proposed-amendments-to-revised-electricity-transmission-code.aspx

4.2 Response to matters raised in Draft Decision

In this section, ElectraNet presents its response to the matters that have been raised in the AER's Draft Decision. ElectraNet sets out how these issues have been addressed in the revised demand forecast, and where ElectraNet has not incorporated an aspect of the AER's Draft Decision on demand forecasts, provides additional information for inclusion in the AER's Final Decision.

4.2.1 Uncertainty of temperature fluctuations on peak demand

In the Draft Decision the AER considered that the method used to produce ElectraNet's demand forecast did not appropriately consider the uncertainty of temperature fluctuations on peak demand.[52] The AER considered that a demand forecast should expressly account for temperature uncertainty, for example, by using a 'one in 10 years' event (10 per cent probability of exceedance).[53]

In planning its network, ElectraNet is obviously very mindful of its obligations under the ETC — most significantly the requirement to plan, develop and operate the network to meet the standards imposed by the ETC and the Rules. This is specifically in relation to the quality of services and the reliability of the network such that there will be no requirements (with respect to quality) or minimal requirements (with respect to reliability) to shed load under normal and reasonably foreseeable operating conditions.[54]

Particularly in light of AEMO's work on demand forecasting methodologies and AEMO's new national demand forecasts, including for South Australia, which are significantly lower than those that had been forecast in previous years, ElectraNet has undertaken a significant amount of work over the past 6 months on demand forecasting in consultation with AEMO and SA Power Networks. This work has been directed at understanding AEMO's forecasting methodology and 2012 forecasts, and how these compare to the forecasting methodology used by SA Power Networks to derive the demand forecasts that ElectraNet had used at a connection point level in its Revenue Proposal.

The outcome of the work that ElectraNet has undertaken with AEMO and SA Power Networks has included the adoption in the revised Revenue Proposal of a 10 per cent probability of exceedance connection point demand forecast for the purpose of non-radial and regional connection point planning. This change in basis for the demand forecasts involves accepting a marginal increase in risk to supply reliability — that is, some customer load may need to be shed under peak load conditions (exceeding 10 per cent probability of exceedance demand forecast conditions) during an outage of a critical transmission element.

ElectraNet's revised Revenue Proposal is based on 10 per cent probability of exceedance connection point demand forecasts provided by SA Power Networks in November 2012. ElectraNet has applied these 10 per cent probability of exceedance demand forecasts to non-radial connection points (i.e. those that are required by the ETC to have duplicate line or transformer capacity). For radial connection points where duplicate line or transformer capacity does not exist the SA Power Networks 2012 peak demand forecast has been used.

52 AER, Draft Decision, page 75.
53 AER, Draft Decision, page 75.
54 Electricity Transmission Code, TC/07, effective 1 July 2013, clause 2.1 (which broadly mirrors the obligation in the version of the Code currently in operation).

ElectraNet wrote to ESCOSA on 26 November 2012 proposing changes to the ETC such that from 1 July 2013 the ETC would expressly provide for connection point demand forecasts to be based on 10 per cent probability of exceedance forecasts. ESCOSA has commenced public consultation on the proposed changes with the closing date for submissions being 30 January 2013.[55] ElectraNet's current understanding is that ESCOSA anticipates making a decision in respect of the proposed amendments by early March 2013.

There is a possibility that the proposed amendments to the ETC in relation to the basis of demand forecasts could result in ESCOSA approving a more onerous demand forecast standard than ElectraNet has incorporated into its revised revenue proposal. If this were to eventuate ElectraNet considers that the AER would be required to take that obligation, and its impact on ElectraNet's forecast capital expenditure, into account in determining its final decision. This is covered in more detail in section 4.4.1.

4.2.2 Photovoltaic generation, embedded generation, and demand response

ElectraNet notes that the appropriate forecast assumptions for each of the photovoltaic generation, embedded generation, and demand response, will be materially different depending on whether peak demand forecasts or 10 per cent probability of exceedance forecasts are derived. As noted above, in its revised demand forecast, ElectraNet has adopted a risk based approach to developing forecast assumptions for these factors that is more consistent with a 10 per cent probability of exceedance approach.

The adoption of a probability based planning standard and the associated revised demand forecasts therefore addresses the AER's concern that the demand forecasts did not appropriately account for photovoltaic generation, embedded generation, and demand response.

ElectraNet is involved in continuing discussions with AEMO and SA Power Networks on the assessment and inclusion of solar PV, embedded generation, demand response and load shedding adjustments for future state-wide and connection point demand forecasts.

4.2.3 Diversity factor in modelling regional forecasts

ElectraNet notes that appropriate diversity assumptions for modelling regional demand forecasts will be different depending on whether peak demand forecasts or 10 per cent probability of exceedance forecasts are derived. One would expect diversity to reduce under more extreme weather conditions and the assumption of no diversity under extreme peak demand conditions has therefore not been unreasonable.

ElectraNet has reviewed historical transmission connection point diversity factors under high demand conditions in light of the adoption of 10 per cent probability of exceedance connection point forecasts and has determined a diversity factor of 3 per cent for application to the demand forecasts adopted in this revised Revenue Proposal.

The revised demand forecasts therefore address the AER's concern that a diversity factor was not applied for modelling regional demand forecasts.

[55] See ESCOSA website, *ElectraNet's Proposed Amendments to Revised Electricity Transmission Code*: http://www.escosa.sa.gov.au/projects/projectdetails.aspx?id=190.

ElectraNet also notes that the AER was critical of SA Power Networks' demand forecasting methodology for not accounting "for the diversity of peak demand across its connection points and regions."[56] ElectraNet does not agree with this criticism. SA Power Networks provides connection point forecasts and diversified sub-regional forecasts (i.e. for ETC grouped connection points), which are based on measured loads at the transmission connection point at the time of system peak demand. Therefore, underlying diversity present in the distribution network is also inherent in the transmission connection point forecasts provided by SA Power Networks. This means the SA Power Networks transmission connection point forecast is by definition a diversification of the discrete distribution network components that are supplied by the individual or grouped connection points.

4.2.4 Demand forecast reconciliation

On 5 November 2012, AEMO concluded a report on 2012 South Australian Forecasts Comparison that was provided to the AER to assist it with its revenue determination for ElectraNet. This report includes a reconciliation between ElectraNet's diversified aggregated peak demand connection point forecasts and AEMO's top down econometric forecast.

The AEMO report acknowledges that the demand forecasts developed by AEMO and SA Power Networks are created for different reasons and that a portion of the difference between the forecasts is explained by the difference between a regional 10 per cent probability of exceedance demand forecast and the maximum demand expected at each connection point at times of extreme temperature.[57] AEMO also acknowledges that its forecasts could be increased by between 20 MW and 30 MW as a result of changes to assumptions on load factor and maximum demand price elasticity.[58]

ElectraNet notes the concern expressed by EMCa in its report:[59]

> We consider that the AEMO demand forecast may have some bias towards under-estimating demand and that a trend forecast such as we have provided, and which lies between the ElectraNet and AEMO forecasts (though much closer to the AEMO forecast) may provide a more valid representation of future demand.

ElectraNet has provided a reconciliation of its revised connection point demand forecast to AEMO's state wide 2012 econometric forecast in Figure 4-1 below. The adoption of a 10 per cent probability of exceedance basis for connection point forecasts and the other associated adjustments made to the forecast assumptions has significantly closed the gap in reconciliation with the AEMO forecast.

56 AER Draft Decision, page 70, 75.
57 Australian Energy Market Operator, *2012 South Australian Forecasts Comparison*, 5 November 2012 page 4.
58 Australian Energy Market Operator, *2012 South Australian Forecasts Comparison*, 5 November 2012 page 6-7.
59 EMCa, *Advice on Forecast Capital and Operational Expenditure, Contingent Projects and Performance Scheme Parameters – ElectraNet Revenue Determination: Technical Review*, 30 October 2012, page D-3, [716].

Figure 4-1: Total state-wide demand forecast reconciliation

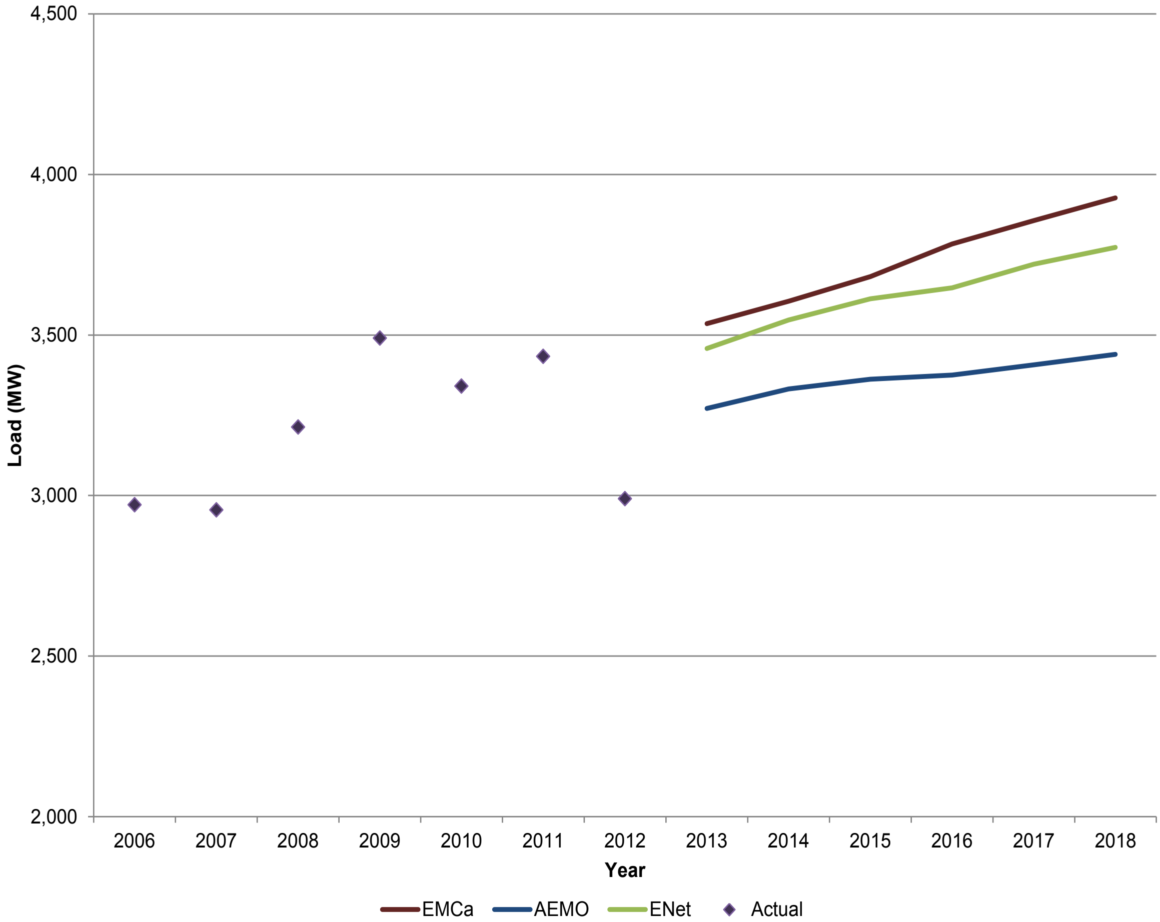

Figure 4-1 plots both the ElectraNet and AEMO state-wide demand forecasts. Both of these forecasts are on a 10 per cent probability of exceedance basis and incorporate adjustments for photovoltaic generation, embedded generation and curtailed load. Thus, the two forecasts can be compared to one another in a manner not previously possible given the peak demand basis of ElectraNet's original forecast. The AER's substitute demand forecast is also included for comparison purposes. ElectraNet considers that the resultant comparison of these forecasts is a reasonable outcome given the differences in forecasting methodologies and the developing maturity of the AEMO and ElectraNet forecast methodologies.

It should be noted that the historical data presented in Figure 4-1 has not been temperature adjusted, and is therefore not directly comparable with the 10 per cent probability of exceedance basis of the forecasts.

As noted in the AEMO report, the methods used to prepare demand forecasts are classified as "work in progress" and are subject to ongoing discussions between the parties and refinement to improve future demand forecasts.

The revised reconciliation of demand forecasts included in this revised Revenue Proposal therefore addresses the AER's concern on this matter.

4.3 ElectraNet 2012 Revised Demand Forecast

Appendix G of this revised Revenue Proposal presents ElectraNet's revised connection point demand forecasts that are based on 10 per cent probability of exceedance connection point forecasts provided by SA Power Networks.

ElectraNet believes that these revised demand forecasts address the issues raised by the AER in its Draft Decision in that the revised forecasts:

- are based on a temperature related 10 per cent probability of exceedance and appropriately consider the uncertainty of temperature fluctuations on peak demand;
- use appropriate adjustments to account for photovoltaic generation, embedded generation, and demand response in a 10 per cent probability of exceedance framework;
- contain appropriate diversity factors for use in regional network planning; and
- include a reconciliation with AEMO's 2012 state-wide summer demand forecasts.

ElectraNet engaged Oakley Greenwood to provide advice and review the forecast methodology used to prepare the revised connection point forecasts in Appendix F to ascertain whether these forecasts provide a realistic expectation of connection point demand for South Australia.

Oakley Greenwood found that the demand forecasts, the methods used in their preparation and the treatment of adjustments to account for photovoltaic generation, embedded generation and demand response are reasonable and provide a realistic expectation of demand. Oakley Greenwood also recommended further development of certain aspects of the demand forecasting methodology. Oakley Greenwood's report can be found in Appendix F.

As noted above, ElectraNet and AEMO have agreed to continue to work together to further develop their respective forecasting methodologies.

ElectraNet considers that the revised connection point demand forecasts provided fully address the AER's concerns over the use of maximum demand forecasts and the other issues covered above. ElectraNet is also confident that these forecasts provide a reasonable basis for assessing load driven capital expenditure and, further, meet the criteria set down in clause 6A.6.7 of the Rules.

For completeness, as stated in its Revenue Proposal and throughout the subsequent review process, ElectraNet notes that it uses AEMO's 10 per cent probability of exceedance forecasts to plan main grid augmentations, which are driven by total demand levels across the network, contrary to the claims made by the AER in its Draft Decision.[60] Of necessity, these forecasts cannot be used for more localised connection point and local planning requirements, for which connection point forecasts are applied, as explained above.

4.4 The South Australian Electricity Transmission Code

The AER concludes in the Draft Decision that the forecast agreed maximum demand agreed between ElectraNet and SA Power Networks is not an applicable regulatory

60 AER, Draft Decision, page 68.

obligation for the purposes of determining the forecast of total capex required for the forthcoming regulatory control period.[61]

Although ElectraNet has incorporated a demand forecast based on 10 per cent probability of exceedance in the revised Revenue Proposal, which it considers addresses the matters raised by the AER in the Draft Decision with respect to forecast demand, ElectraNet wishes to be clear that the requirement for ElectraNet to react to a change to forecast agreed maximum demand is an applicable regulatory obligation for the purposes of determining forecast capex.

The AER draws a distinction between what the AER considers to be the relevant standard, being contracted agreed maximum demand, and not forecast agreed maximum demand. The AER states that forecast agreed maximum demand is not the basis for the ETC reliability standard.[62]

ElectraNet agrees that the relevant reliability standard is set by reference to contracted agreed maximum demand. This is clear from clauses 2.5 to 2.9 of the ETC.However, that does not mean that the requirement in the ETC to plan the network in a manner to avoid a future breach of a reliability standard in clause 2 by reference to a change in forecast agreed maximum demand is not an “applicable regulatory obligation or requirement” associated with the provision of prescribed transmission services.

The term “regulatory obligation or requirement” is defined in the National Electricity Law. It includes an obligation or requirement under an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, that materially affects the provision, by a regulated network service provider, of electricity network services that are the subject of a distribution determination or transmission determination.[63]

ElectraNet submits that the obligation under the ETC to ensure that, in the event that a change in forecast agreed maximum demand will result in a future breach of the reliability standards in clause 2 of the ETC, it has taken steps to avoid that breach within 12 months of the identified future breach date, is an applicable regulatory obligation or requirement by reference to the definition of that term in the National Electricity Law. It is an obligation or requirement under an instrument made or issued under or for the purposes of an Act of a participating jurisdiction. The AER appears to accept this, without necessarily accepting that the obligation to plan the network by reference to forecast agreed maximum demand is an applicable regulatory obligation or requirement.[64]

In addition, ElectraNet notes the overarching role of the revenue and pricing principles as part of the AER’s final decision in respect of ElectraNet’s forecast capital expenditure. In particular, section 7A(2) of the NEL states:

61 AER, Draft Decision, page 94.
62 AER, Draft Decision, page 92.
63 National Electricity Law, section 2D(1)(b)(v).
64 AER, Draft Decision, page 91.

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

   a) providing direct control network services; and

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

The obligations under the ETC are mandatory licence obligations. For the reasons set out above, they are clearly 'regulatory obligations' for the purposes of both the National Electricity Law and the Rules. Therefore, in assessing forecast capex for the forthcoming regulatory control period, forecast agreed maximum demand is a highly relevant consideration.

The obligation under the ETC to react to a change in forecast agreed maximum demand contributes to the costs of ElectraNet in providing direct control services. On this basis, the AER is required to take into account those costs when determining ElectraNet's forecast capex for the purposes of its transmission determination. This includes the costs incurred by ElectraNet to build the network in a manner which ensures compliance with the ETC.

As noted above, ElectraNet wrote to ESCOSA on 26 November 2012 proposing various amendments to the ETC.[65] ElectraNet's proposed amendments seek to alter the definition of forecast agreed maximum demand such that from 1 July 2013 it will expressly provide for the demand forecast to be based on a 10 per cent probability of exceedance methodology. ESCOSA has commenced public consultation on the proposed changes with the closing date for submissions being 30 January 2013.[66] ElectraNet's current understanding is that ESCOSA anticipates making a decision in respect of the proposed amendments by early March 2013.[67]

ElectraNet does not have any reason to expect that ESCOSA will not amend the ETC in the manner sought by ElectraNet. However, there remains a risk that ESCOSA will not amend the ETC as sought by ElectraNet and could, for example, amend the ETC to make it explicit that the demand forecast is not to be based on a temperature related probability of exceedance, or that if it is, it is to be based on a higher standard, for example, a 'one in 20 years' event, or 'one in 50 years'.

ElectraNet submits that if the outcome of the ESCOSA consultation was to require the network to be planned by reference to a change in forecast agreed maximum demand, with that demand to be forecast using a higher standard than 10 per cent probability of exceedance, the AER would be required to take that into account in making its final decision. This is not because the demand forecast generated by that requirement was or was not a realistic expectation of the demand forecast required to achieve the capital expenditure objectives, but because the requirement to plan the network to that standard (and the capex necessary to meet that requirement) would be an applicable regulatory obligation with which ElectraNet must comply.

4.4.1 Pass through mechanism

The possibility exists that the ESCOSA decision in relation to the proposed amendments to the ETC will not conclude in time for consideration by the AER as part of its final decision.

65 ElectraNet letter to ESCOSA dated 26 November 2012 attaching proposed amendments to ETC (See ESCOSA website).

66 See ESCOSA website, *ElectraNet's Proposed Amendments to Revised Electricity Transmission Code*: http://www.escosa.sa.gov.au/projects/projectdetails.aspx?id=190.

67 Email from Mr Stuart McPherson (ESCOSA) to Mr Rainer Korte (ElectraNet) dated 13 December 2012.

Should the ESCOSA decision in respect of the ETC ultimately be one that is consistent with ElectraNet's revised Revenue Proposal, and the AER's Final Decision, then the fact the ESCOSA decision concludes after the AER's Final Decision will be of no consequence. However, the possibility exists that the ESCOSA decision will not be concluded prior to the AER's Final Decision and that its decision will result in a more onerous forecast demand obligation under the ETC than that which has been proposed by ElectraNet and allowed by the AER, as part of its forecast capital expenditure for the purposes of ElectraNet's transmission determination.

As such, in the event the ESCOSA decision is not concluded by the time the AER issues its Final Decision, the AER should approve an appropriate pass through mechanism as part of its Final Decision which would be triggered in the event the ESCOSA decision results in a more onerous forecast demand obligation under the ETC than the demand forecasts accepted by the AER as part of its final decision. Such a pass through event would allow ElectraNet to recover the actual additional capital costs it is required to incur as a result of complying with that more onerous obligation under the ETC during the course of the next regulatory control period.

ElectraNet considers that an appropriate pass through mechanism to cover for this possibility is something that the AER can accommodate within its Final Decision, irrespective of the transitional provisions under Chapter 11 of the Rules which provides a timeframe after which ElectraNet is unable to submit to the AER for a 'pass through event'. The AER has two options in this respect; it could accept an out of time pass through event proposal from ElectraNet, in effect waiving the procedural time frame under the transitional provisions. Alternatively, it could, of its own accord, approve its own pass through event which would apply to ElectraNet if the circumstances set out above were to arise.

For the reasons set out below, ElectraNet considers it within the AER's discretion to do this.

4.4.2 The transitional provisions under Chapter 11

The relevant transitional provision in Chapter 11 of the Rules is as follows:

> 11.49.4 Transitional arrangements for ElectraNet and Murraylink
>
> a) Each of ElectraNet and Murraylink may, not later than 30 days after the commencement date, submit to the AER a proposal as to the events that should be defined as pass through events under clause 6A.7.3(a1)(5) for the purposes of its Revenue Proposal for the next regulatory control period, having regard to the nominated pass through event considerations.
>
> b) If within 30 days after the commencement date the AER receives a proposal under paragraph (a) from ElectraNet or MurrayLink, then the AER must treat the proposal as if it had been included in the relevant Transmission Network Service Provider's Revenue Proposal for the next regulatory control period and make a decision under clause 6A.14.1(9) in respect of that proposal.

The transitional provision provides a time frame of '30 days after the commencement date' within which ElectraNet can submit to the AER a proposal for a 'pass through event'. The 'commencement date' is defined in clause 11.49.1: as 'the date the Amending Rule commences operation'. The 'date the Amending Rule commences operation' was 2 August 2012.

ElectraNet considers that despite the fact that it may be time barred from proposing its own pass through event to cover the circumstances set out above, the timeframe set out under the transitional arrangements serves a procedural purpose. It is within the AER’s power to waive this procedural limitation and allow ElectraNet to propose its own pass through event for incorporation into the final decision.

Alternatively, it is open for the AER to incorporate its own pass through event as part of the final decision which deals with the circumstances set out above to ensure that ElectraNet is able to recover its efficient costs of building the network as part of its ETC obligations.

ElectraNet proposes to notify the AER once the outcome of the amendments to the ETC is known. If it appears ESCOSA’s final decision on the amendments will be delayed, ElectraNet reserves the right to work with the AER at that point to develop a suitable pass through event that the AER could incorporate in its Final Decision.

5. Asset Management Framework

5.1 Summary

In its Draft Decision, the AER accepted ElectraNet's integrated asset management framework as consistent with good industry practice and noted that this framework is based on: [68]

- comprehensive asset condition intelligence and data;
- risk assessment driven work prioritisation; and
- a prioritisation model based on total asset lifecycle.

However, the AER did not approve ElectraNet's proposed capex or opex forecasts and instead included substitute forecasts in its Draft Decision. In effect, the AER assumed that ElectraNet could obtain additional efficiencies from its asset management framework, and concluded that an adjustment should be made to ElectraNet's expenditure forecasts.

The AER therefore imposed a substitute capital expenditure forecast on the basis that ElectraNet's condition based monitoring would yield savings in replacement and refurbishment expenditure. In particular, the AER argued that it:

- expects that ElectraNet's expanded and improved field maintenance program in combination with its asset management framework ought to lead to lower replacement capex in the future (page 101);
- considers that the full cost of deployment and implementation, estimated at $50 million by EMCa, should be recovered over a reasonable timeframe (page 107); and
- considers that ElectraNet should be able to defer at least $50 million of replacement capex in the 2013-2018 regulatory control period (page 101).

The AER's conclusions were based on advice from its consultant EMCa who concluded:

> "There has not been adequate justification for risk / cost trade-offs or current cost/ future cost trade-offs that are inherent in the proposed maintenance, refurbishment and asset replacement programs. EMCa did not accept the argument that these programs are insensitive to risk and only high risk conditions are being addressed."[69]

The AER was also concerned that:[70]

> "The asset replacement threshold is developed without reference to economic analysis."
>
> "A significant number of defects that drive corrective maintenance are "asset related" and do not have safety/ environmental or reliability/ availability impacts."
>
> "ElectraNet has not provided information about the cut-off points at which asset refurbishment projects are undertaken."

68 AER, Draft Decision, page 103.
69 AER, Draft Decision, page 105.
70 AER, Draft Decision, page 107.

In the absence of the $50 million capex reduction referred to above, the AER concluded that ElectraNet will not only recover the implementation cost of the integrated asset management program but also recover the economic benefits inherent in the capex / opex trade off which the AER considered ElectraNet had not accounted for in the expenditure forecast. The AER considered that such an approach is inconsistent with the national electricity objective, in that the AER considered that it does not recognise the long-term interests of consumers.

As the issues raised by the AER are relevant to both ElectraNet's capital and operating expenditure forecasts, it is appropriate to address this matter before turning to the specifc expenditure forecast chapters.

As explained in further detail below, ElectraNet supports the AER's objective of ensuring expenditure forecasts are efficient and consistent with those of a prudent operator, but strongly disagrees with the analysis undertaken and the conclusions drawn by EMCa and the AER in relation to the incremental costs and benefits of ElectraNet's enhanced condition-based maintenance regime.

In summary, ElectraNet does not accept that there is a reasonable basis for the AER's proposed $50 million reduction in ElectraNet's replacement and augmentation program. In particular:

- the AER's assumed incremental implementation costs of the enhanced maintenance regime have been significantly overstated, and the AER has also disallowed most of these costs.
- ElectraNet's expenditure forecasts have been developed based on the best asset condition information available from its enhanced condition-based maintenance regime and so any economic benefits have already been taken into account in the forecast period through deferred substation and line replacement investment timing.
- there can be no reasonable expectation that the information gathered through the new expenditure which is focused on transmission lines will defer further replacement capex in the 2013-2018 regulatory period – this is because there is no transmission line replacement capital expenditure included in the forecast.

The following sections address in more detail each of the above matters raised in the AER's Draft Decision.

5.2 Incremental cost of enhanced maintenance regime

AER Draft Decision

In its Draft Decision the AER approved scope changes in routine maintenance, but removed $50 million of replacement capex on the basis that:[71]

> "…the AER expects that ElectraNet's expanded and improved field maintenance program in combination with its asset management framework ought to lead to lower replacement capex in the future. That is, the AER considers that ElectraNet should be able to defer at least $50 million of replacement capex".

The $50 million reduction in replacement capex was based on EMCa's estimate of the incremental cost of deploying an enhanced condition-based maintenance regime in the

[71] AER, Draft Decision, page 101.

current and forecast regulatory control periods[72] and the notion that this investment needs to be returned to customers via reduced forecast expenditure allowances by the end of the forthcoming period.

ElectraNet's Response

The AER and EMCa found that the design, structure and components of ElectraNet's condition-based asset management framework are consistent with good industry practice.[73]

It is important to understand that in accordance with good industry practice, ElectraNet already had a condition-based maintenance regime in place prior to the commencement of the current regulatory period and that the AER approved expenditure allowances for enhancements to this regime in its 2008 revenue determination.

In relation to the $50 million estimate of the incremental cost of deploying an enhanced condition-based maintenance regime, EMCa stated:[74]

> "This is an incremental cost estimate – that is, it reflects the costs that ElectraNet appears to have incurred (or will incur) in designing and implementing the current regime, relative to what it would have incurred, and was incurring, prior to implementing this regime".

ElectraNet understands how EMCa has derived its cost estimate of $50 million, but this is not the incremental cost of decisions ElectraNet has made in the current regulatory period to enhance its condition-based maintenance regime. As explained below, EMCa has significantly overstated the incremental costs of ElectraNet's condition-based maintenance regime. As a consequence, EMCa has imposed an equivalent reduction in replacement capital expenditure that is also overstated. Even if EMCa's approach were correct – which it is not – the cost estimates are incorrect and must be amended.

EMCa's estimate includes all routine maintenance, operational refurbishment and support costs associated with operating ElectraNet's condition-based maintenance regime. In other words, the $50 million estimate effectively assumes that prior to the current regulatory period ElectraNet undertook no condition-based maintenance activities at all. This is clearly incorrect.

Table 5-1 below sets out ElectraNet's cost estimate of deploying its enhanced condition-based maintenance regime compared to EMCa's estimate.

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72 EMCa, *ElectraNet technical review,* October 2012 (EMCa report), page D-5.
73 AER, Draft Decision, p103 and EMCa report, page D-4.
74 EMCa report, page D-5.

Table 5-1 Incremental cost of enhanced maintenance regime ($2011-12)

Cost estimate	2008-2013	2013-2018	Total
Routine Maintenance	9.0	15.0	**24.0**
Operational refurbishment	4.9	15.0	**19.9**
Asset manager support	2.4	5.4	**7.8**
Total opex	**16.3**	**35.4**	**51.7**
Capex (IT)	1.0	-	**1.0**
Total - EMCa	**17.3**	**35.4**	**52.7**
Routine Maintenance	2.7	5.1	**7.8**
Operational refurbishment	4.9	14.4	**19.3**
Asset manager support	1.0	1.5	**2.5**
Total opex	**8.6**	**21.0**	**29.6**
Capex (IT)	0.5	-	**0.5**
Total - ElectraNet	**9.1**	**21.0**	**30.1**

The benefits of the current period investment are already reflected in lower capital requirements in the forecast and future regulatory periods (for example the deferral of substation replacements). The benefits of the next period investment (approximately $15 million of which relates to transmission line condition assessment projects under the operational refurbishment program) will be realised in future periods.

Also in relation to the costs of the enhanced maintenance regime, EMCa stated:[75]

> "…the asset condition data base that is being developed to support the regime is comprehensive and therefore costly. With full analysis of costs and options, the majority of benefits could be achieved with considerably lower deployment costs by relying on sampling and asset type focus."

The EMCa assumption that ElectraNet's forecast costs are based on the collection and analysis of full asset condition data across every element in the network rather than appropriate sampling is incorrect.

In the implementation of its enhanced framework, ElectraNet's condition assessment program is based on prioritised asset type assessment, using sampling techniques to gather representative information on the status of its assets, wherever efficient and effective, through:

- targeted testing of line assets and components, and
- prioritised substation asset and component condition assessment updates.

This provides a cost-effective baseline on asset condition to deliver ongoing benefits through efficient whole of life asset management.

75 AER, Draft Decision, page 105.

In summary, in relation to the claimed costs of the regime:

- the incremental cost of the enhanced condition based maintenance regime in this period and the next totals $30 million (not $50 million);
- of this, $9 million has been incurred in the current regulatory period, consistent with the maintenance strategy endorsed by the AER in its 2008 determination;[76]
- any question about the benefits of decisions made in the current regulatory period to implement an enhanced condition-based maintenance regime can only legitimately relate to the remaining $21 million cost estimate shown in Table 5-1; and
- at the same time as disallowing $50 million of replacement capex, the Draft Decision disallows the large majority of the condition assessment component of the operational refurbishment program (i.e. $15 million of the $21 million above). This work is fundamental to better understanding the condition of transmission lines and the extent of future work that will be required to maintain and extend the life of these assets (and thereby defer future replacement capex). This is internally inconsistent. In effect, the AER's Draft Decision is factoring in a future expected benefit but disallowing the investment costs that need to be incurred to realise that benefit. As discussed below, the Draft Decision compounds this error by incorrectly assuming that the benefits will accrue in the forthcoming regulatory period.

5.3 Ability to defer replacement capex

AER Draft Decision

The AER considers that ElectraNet should be able to defer at least $50 million of replacement capex in the 2013-2018 regulatory control period based on EMCa's assessment of the incremental cost of ElectraNet's enhanced maintenance regime in the current regulatory period and the next (page 101).

ElectraNet's Response

The previous section demonstrated that EMCa's $50 million estimate of the incremental cost of the enhanced maintenance regime is significantly overstated.

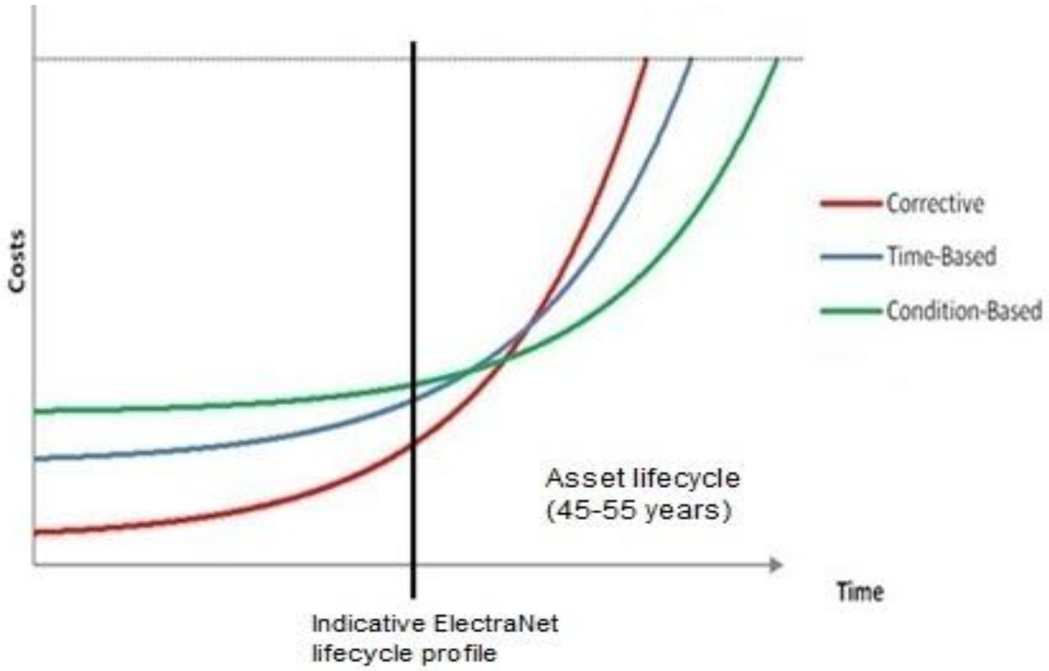
This section addresses EMCa's and the AER's expectation that it is reasonable to expect that benefits of at least this amount should be realised in the 2013-2018 regulatory period through deferral of replacement capex.

ElectraNet agrees with the AER that "…at least the costs of the framework would be recovered over a reasonable time horizon" (page 107). The question to be determined is what is a reasonable time horizon?

Figure 5-1 illustrates the well accepted principle that while a condition based maintenance regime represents the lowest long-run cost maintenance approach in managing long-lived assets, it requires higher initial implementation costs in order to deliver these benefits over time.

76 "The circumstances of ElectraNet, including changing asset management practices and implementation of new maintenance regimes, means that relying solely on base year extrapolation to forecast the opex requirement would not result in an efficient allowance.", AER, Final Decision, 11 April 2008, page 74.

Figure 5-1 Comparison of alternative maintenance cost regimes



Source: *Strategy for Condition Based Maintenance and Updating of substations*, CIGRE 1996:23-105

The figure above illustrates that for a given population of assets, a condition-based approach results in the longest asset life at lowest whole of life cost. While lower short-term costs are possible under alternative approaches, this results in the deferral of risk and greater overall cost.

The initial investment cost required in order to establish an efficient condition-based regime includes:

- increased asset inspection and assessment;
- new systems and processes to analyse asset condition information; and
- identification and rectification of previously latent defects in the existing asset base.

Figure 5-1 indicates that ElectraNet's current position is one of investing now to deliver long-term benefits over the asset life cycle. It illustrates that the investment in condition-based monitoring cannot be expected to deliver a short payback period (relative to the 45-55 year asset lifecycle), as EMCa has incorrectly assumed.

Also the incremental implementation cost of $21 million in the next regulatory period relates almost entirely to transmission lines, comprising approximately $15 million of condition assessment works (putting aside for the moment that the Draft Decision excludes this amount) and $4 million of enhanced condition-based routine maintenance works.

There can be no reasonable expectation that the information gathered through this expenditure in the next period (even if allowed) will defer any further replacement capex in the 2013-2018 regulatory period since there is no transmission line replacement capex included in the forecast.

In reality, the pay-back for the incremental cost of gathering the transmission line condition information will be in delivering transmission services at lower long-run cost beyond the 2013-2018 regulatory period. The AER is therefore incorrect to conclude that it must make an adjustment to ElectraNet's proposed replacement capital expenditure to deliver an additional pay-back to customers in the next regulatory period.

5.4 Economic analysis

AER Draft Decision

In the Draft Decision the AER has expressed concerns about the economic basis for the asset management decisions reflected in ElectraNet's capex and opex forecasts. In particular the Draft Decision includes the following key reasons for the AER's decision not to accept ElectraNet's forecasts.[77]

> "ElectraNet's high level management decisions have not yet been fully informed by its integrated asset management framework and therefore expenditures have not been adequately justified under its comprehensive governance systems."

> "ElectraNet has not assessed the economic benefits of its asset management framework. It has also not assessed the economic benefits of reducing maintenance expenditure by undertaking targeted replacements. Nor has it shown the economic benefits of deferring replacements by increasing opex."

ElectraNet's Response

ElectraNet considers that its replacement capex, corrective maintenance and operational refurbishment forecasts are required in order for ElectraNet to achieve the operating and capital expenditure objectives.

A brief summary of ElectraNet's capex replacement and maintenance decision framework follows.

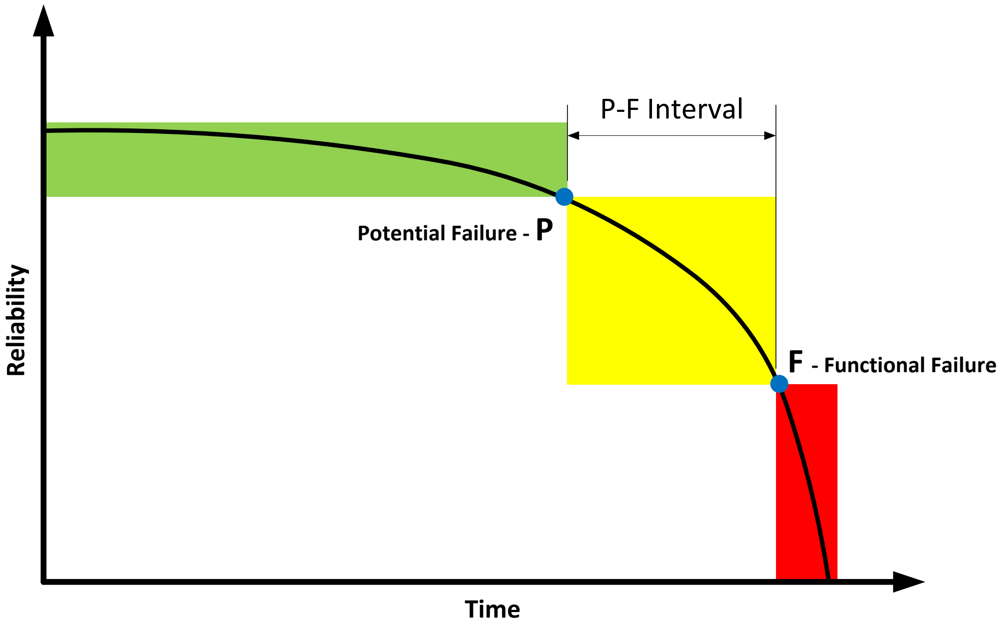
<u>Capex replacement and maintenance decision framework</u>

The condition and serviceability of all assets deteriorates as they approach the end of their technical life decreasing reliability and leading to increased maintenance effort and ultimately replacement to maintain serviceability.

The task of the asset manager is to understand where assets are in their lifecycle and all reasonably expected asset failure modes and to develop an appropriate timely response based on the risk and consequence of the failure modes identified. This is illustrated in Figure 5-2.

[77] AER, Draft Decision, page 29.

Figure 5-2 Asset lifecycle condition and performance



ElectraNet's System Condition and Risk (SCAR) system has been developed to minimise corrective maintenance effort in the long term by systematically identifying for each identified failure mode the maximum acceptable time to respond based on the risk and consequences of failure.

ElectraNet's Transmission Asset Lifecycle (TALC) assessment framework has been developed for systematically identifying where an asset is in its lifecycle and when it is likely to reach end of life.

Fundamental to prudent asset management is the need to understand what is known as the P-F interval, which for a particular type of asset is the expected time interval between:

- Potential failure – the point at which the condition of the asset begins to deteriorate and resistance to failure is compromised; and
- Functional failure – where the asset fails and is no longer serviceable.

The rate of change of asset condition after it reaches the point of potential failure and therefore the time before asset failure occurs is dependent on a wide range of factors, which may be internal and / or external to the asset. The P-F intervals for different types of transmission assets vary from months to years.

The outcomes of the Victorian Bushfire Royal Commission underscore the importance of asset managers understanding asset P-F interval and taking appropriate action before asset failure occurs.

> "International expert Professor Nicholas Hastings explained that an inspection regime's suitability for limiting asset failure should be assessed by reference to the extent to which the regime allows incipient failures to be detected before they proceed to full functional failure - that is, the asset failing while in service. The regime should take into account how the assets fail, how failures can be detected and the effect of failure."[78]
>
> "Additionally, the rates of failure of some important network components are climbing as those components age. Increasing failure rates warrant increased opportunities for detection."[79]

In light of the above background the following subsections briefly explain the basis of ElectraNet's decision making in relation to its corrective maintenance, operational refurbishment and replacement capex forecasts.

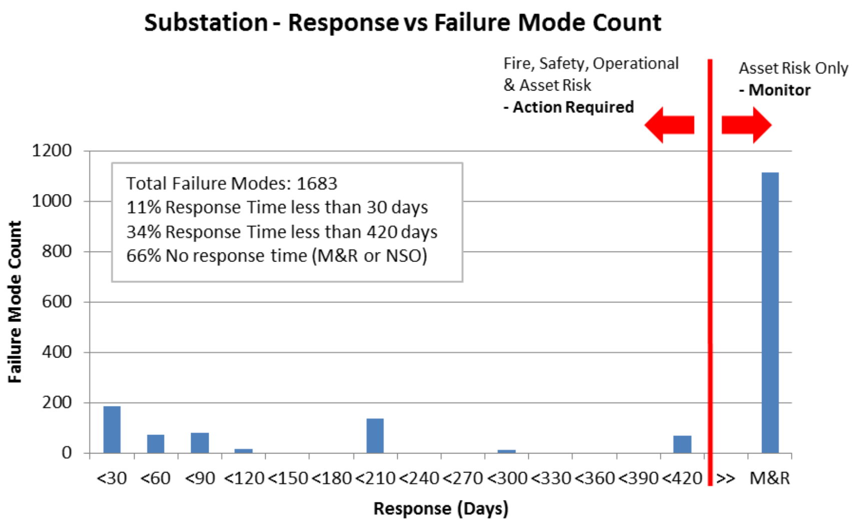
Further information on ElectraNet's capex replacement and maintenance decision framework can be found in Appendix P.

Corrective maintenance decision making

The asset defects recorded in ElectraNet's SCAR system each have a required response time that has been determined as the longest acceptable time to take corrective action within the expected P-F interval for the particular asset. The P-F intervals for each type of asset have been determined based on the best asset management data available by appropriately qualified asset management professionals within ElectraNet and reviewed by external experts.

Figure 5-3 and Figure 5-4 show over all substation and transmission line asset types the required response times recorded in SCAR for all identified failure modes.

Figure 5-3 SCAR substation failure mode response times

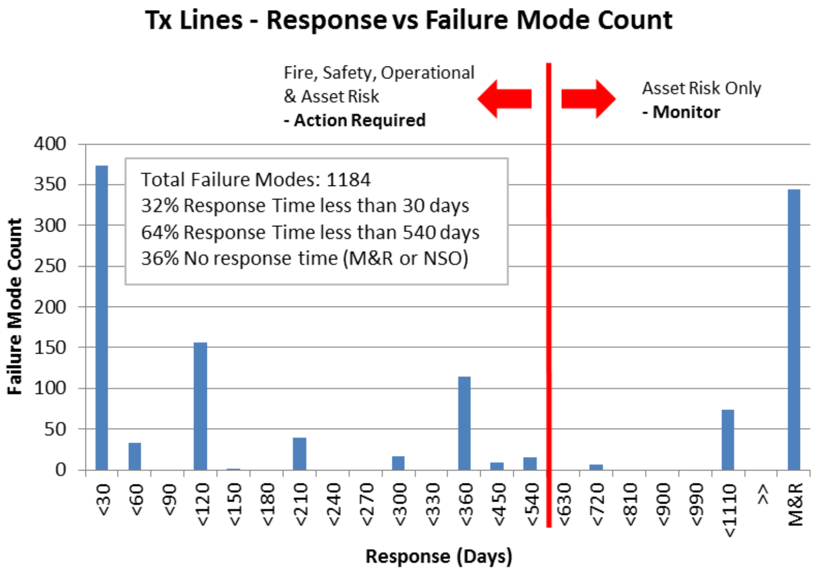


This diagram shows that the SCAR coding profile for substations is dominated by "monitor and review" (M&R) defects which also includes defects to be addressed at the next scheduled opportunity (NSO) for which no other immediate action is taken.

78 *Victorian Bushfire Royal Commission report*, page 160.
79 *Victorian Bushfire Royal Commission report*, page 161.

Only 11 per cent of the identified potential failure modes related to fast failure mode high risk asset defects for which corrective action is required within 30 days.

Figure 5-4 SCAR transmission lines failure mode response times



The SCAR coding profile for transmission lines reflects a greater number of shorter response times associated with high risk fire start, safety and operational defects (<120 days 48 per cent) and asset risk defects having fire start risk consequences but with longer P-F intervals (>120 and <540 days 17 per cent). Defects with no response required (monitor and review) are asset risk only with no fire start risk and represent the remaining 36 per cent of failure modes.

ElectraNet's corrective maintenance forecast which is discussed in section 7.5.2 includes asset defects that have required response times well short of the end of the 2013-2018 regulatory control period. Therefore, there is no prudent "correct later" option for addressing these defects beyond the 2013-2018 period (deferral of 5 years or more). The identified assets would be expected to fail within this period based on their expected P-F intervals.

Further information on ElectraNet's SCAR framework can be found in Appendix O.

<u>Operational refurbishment decision making</u>

For asset defects with longer required response times exceeding those of corrective maintenance, operational refurbishment plans are developed by considering all asset defects where possible by plant group so works can be packaged as operational projects for more efficient delivery of the maintenance works required.

The operational refurbishment projects that comprise ElectraNet's operational refurbishment forecast are set out in section 7.5.3. These projects can be categorised as addressing:

- condition assessment of transmission lines to better understand where these lines are in their asset lifecycle and thereby to enable future asset management decisions to minimise long-run cost (discussed earlier in this chapter).
- safety and environmental issues, including potential fire start risk.

- more general asset deterioration and failure issues.

ElectraNet considers that the works for transmission line condition assessment are critical to help complete its understanding of the condition of transmission lines to facilitate delivery of transmission services at lowest long-run cost (as discussed earlier) and are therefore justified on an economic basis.

The works required to address safety and environmental issues are also necessary and prudent to be undertaken on public safety grounds based on qualitative risk assessment and analysis of potential failure consequences.

The remaining works are supported by a high level cost benefit analysis based on quantified failure consequences and impacts.

Further information on ElectraNet's Asset Refurbishment Plan for the 2013-2018 regulatory control period can be found in Appendix Q.

Replacement capex decision making

As assets approach end of life their behaviour becomes more uncertain which is reflected in deteriorating asset reliability and availability performance. The aim of ElectraNet's TALC assessment framework is to identify the overall position of a group of assets (e.g. a substation) on the asset lifecycle performance curve.

Asset replacement may be justified when the performance of the asset is unsafe to operate, it is environmentally unacceptable or is unpredictable with an increasing impact on maintenance costs and unserved energy to customers.

The threshold for replacement is based on evidence that an asset has reached a stage where it is no longer possible to manage one or more of these key aspects.

Once this point is reached ElectraNet undertakes a comprehensive TALC assessment to test its understanding of the assets condition and associated risks and consequences in more detail. A cost benefit assessment is also undertaken. Table 5-2 summarises the outcomes of the cost benefit assessment for the relevant replacement projects included in ElectraNet's revised replacement capex forecast.

Table 5-2 Substation replacement cost benefit assessment ($2012-13)

Project	Project Cost $2012-13	Present Value Cost		
		Period 1 2008-2013	Period 2 2013-2018	Period 3 2018-2023
Baroota	17.5	77	128	227
Kanmantoo	14.3	24	25	32
Mannum to Adelaide (SA Water pump stations)	58.4	113	230	428
Morgan to Whyalla (SA Water pump stations)	65.1	118	396	812
Neuroodla	11.2	16	22	29
Mt Gunson	11.4	14	16	21

The results of the cost benefit analysis summarised in Table 5-2 show that the optimal timing for these replacement projects is now. Deferral of these projects would result in increases in maintenance costs and the cost of customer supply outages that together outweigh the costs of undertaking the projects.

Further information on ElectraNet's replacement capex and maintenance decision framework can be found in Appendix P.

5.5 Benefits of the enhanced condition based maintenance regime

As discussed earlier, the pay-back for the incremental cost of gathering the transmission line condition information will be in delivering transmission services at lowest long-run cost beyond the 2013-2018 regulatory period.

However the following provides examples of where benefits are already being realised from the enhanced condition information available.

Substations

Implementation of condition monitoring with respect to substations has been completed in the current period. The full benefit of this enhanced asset condition information has been built into the forecasts for the next regulatory control period through the deferral of substation replacement projects.

Table 5-3 below lists the substation projects that have been deferred from the 2013-2018 forecast period from the original replacement program documented in ElectraNet's Asset Management Plan (2007) on the basis of enhanced asset condition information.

In summary, this has resulted in the deferral of 7 full substation replacements of an indicative estimated capital value of $275 million.[80] The impact of these deferrals has been fully reflected in the 2013-2018 capex forecast.

Table 5-3 Substation replacement deferral from the 2013-2018 regulatory period

Substation	Region	Indicative Replacement Cost ($m)
Happy Valley 275kV & 66kV substation	Metro	53
Brinkworth 275kV & 132kV substation	Transmission	33
Dry Creek 66/11kV Power Station	Metro	8
Mount Gambier 132/33/11kV substation	South East	18
Berri substation	Riverland	16
North West Bend substation	Riverland	23
South East substation	Transmission	121
Total		**273**

Source: ElectraNet Asset Management Plan 2007

80 These deferrals are in addition to substation replacement works deferred due to alignment with augmentation that has moved due to the adoption of 10 per cent probability of exceedance demand forecasting.

Transmission Lines

Asset condition information collected on transmission lines to date (currently nearing 40 per cent completion) will deliver substantial investment deferral benefits in the next period and beyond.

The line refit program included in the capex forecast, which has been assessed as extending the life of the relevant transmission lines by an average of 15 years, is an example of the benefits of the enhanced condition information already available for transmission lines.

5.6 Conclusion

ElectraNet agrees with the AER that the benefits of moving to an enhanced condition-based maintenance regime should be considered with a view to recovering the associated costs over a reasonable time horizon.[81] Accordingly, it is appropriate that consumers should receive the benefits of the enhanced maintenance program as these are delivered over time.

As above, ElectraNet supports the well-established principle that investing in an enhanced condition-based maintenance regime is a necessary precondition for delivering transmission services at lowest long-run cost (accepting that up front implementation cost will be required to deliver such a regime). All of the benefits from the 2008-2013 part of the program are fully factored into the capex forecasts for 2013-2018, and the enhanced condition-based maintenance regime will continue to deliver benefits into the future.

However, the Draft Decision is incorrectly based on an expectation that the investment would be fully recovered through lower replacement capex in the 2013-2018 regulatory control period. Improved asset condition information cannot provide such immediate savings. Instead, the benefits are achieved over the longer term by optimising future maintenance, refurbishment and replacement decisions over the asset life cycle. Consumers should therefore receive the benefits as they are delivered, and it is not appropriate for the AER to seek to infer or pass through future benefits before they can be achieved.

The Draft Decision states:[82]

> "In the absence of this capex adjustment, ElectraNet will not only recover the implementation cost of this program but also recover the economic benefits inherent in the capex / opex trade off which it has not accounted for in its expenditure forecast."

This is incorrect. ElectraNet agrees that consumers should receive the benefits of the enhanced maintenance program but, as demonstrated above, there is no reasonable basis for the reduction in ElectraNet's replacement and augmentation program because:

- the incremental implementation costs of the enhanced maintenance regime have been significantly overstated;
- the expenditure forecasts have been developed based on the best asset condition information available from ElectraNet's enhanced condition-based maintenance regime and so any economic benefits have already been taken into account in the forecast period through deferred substation and line replacement investment timing;

81 AER, Draft Decision, page 108.
82 AER, Draft Decision, page 109.

- there can be no reasonable expectation that the information gathered through the new expenditure (even if it is allowed) which is focused on lines will defer further replacement capex in the 2013-2018 regulatory period. This is because there is no transmission line replacement capex included in the forecast; and
- more generally ElectraNet's replacement capex forecast is supported by detailed asset condition assessments and cost benefit analysis. There is no basis for the AER's view that further efficiencies can be achieved.

ElectraNet has therefore not incorporated the capex / opex trade-off reduction in replacement and refurbishment in its revised capex forecast.

6. Capital Expenditure

6.1 Summary

Chapter 5 of ElectraNet's Revenue Proposal (May 2012) set out ElectraNet's capex forecasting methodology for the next regulatory control period, together with the key inputs and assumptions used in determining the capex forecast.

ElectraNet's Revenue Proposal forecast a minor increase in capital expenditure in real terms (in the order of 1 per cent) based on the following cost drivers:

- continuing growth in peak demand and strengthened ETC delivery requirements, which drive the need for ongoing transmission investment to meet mandated reliability standards;
- an increase in the volume of assets nearing the end of their useful lives, which requires increased levels of asset replacement expenditure;
- additional investment required to refurbish and extend the life of transmission lines based on asset condition and risk mitigation;
- an increase in land and easement acquisition requirements in order to secure land and easements in a timely and prudent manner, to meet emerging new transmission line investment needs; and
- real wages growth and related cost pressures caused by a projected strengthening in employment demand in the mining and construction sectors in South Australia.

In its Draft Decision, the AER assessed ElectraNet's forecast capex for the next regulatory control period. In undertaking its assessment the AER:

- accepted ElectraNet's project management methodologies as being appropriate, and accepted ElectraNet's cost estimation processes as being comprehensive and likely to produce reliable and accurate cost estimates (page 121);
- considered that ElectraNet has adopted good external and internal benchmarking practices to drive its asset management decisions (page 121);
- approved ElectraNet's proposed efficiency adjustment factor, acknowledging ElectraNet's move to proposing capex efficiency gains (page 122);
- did not approve ElectraNet's forecast capex of $894.1 million ($2012-13) for the 2013-2018 regulatory control period, and estimated a substitute capex forecast of $641.9 million ($2012-13) (page 110);
- in arriving at its substituted capex forecast, applied the following adjustments to ElectraNet's capex forecast ($2012-13).[83]
  - approved the application of a cost estimation risk factor, but substituted ElectraNet's proposed risk factor of 4.9 per cent with its own value of 2.6 per cent and 0 per cent for replacement and refurbishment projects (page 122);
  - applied a prudency adjustment of 7 per cent or $31.7 million ($2012-13) to all replacement and refurbishment projects (page 126);

83 The sum of the individual adjustments exceeds the aggregated impact.

  - approved ElectraNet's methodology for the calculation of materials escalation but substituted its own real cost escalators for labour costs, exchange rates, material input costs, and land values reflecting updated information (pages 63 and128);
  - did not approve ElectraNet's proposed strategic land and easement acquisition forecast of $65.8 million and substituted $13.4 million ($2012-13) as an indicative forecast (page 133);
  - reduced load driven project capex by $103.7 million based on its substituted demand forecast, comprising $17.6 million of augmentation, $29.6 million of connection and $56.5 million ($2012-13) of replacement expenditure (page 133);
- approved ElectraNet's proposed method for determining its benchmark equity raising costs, and substituted an updated value based on the Draft Decision RAB roll forward and indicative WACC (page135);
- approved ElectraNet's capex forecast for Security / compliance, Inventory / spares, Business IT and Buildings / facilities project categories as reasonable (page 136); and
- accepted ElectraNet's proposed replacement capex relating to SA Water pumping station assets as prescribed expenditure, noting some concerns over the operation of clause 11.6.11 of the Rules (page 126).

As explained in Chapter 5, the AER also imposed a capex / opex trade-off reduction on replacement and refurbishment projects of $50 million (page 108). ElectraNet does not accept this reduction for the reasons set out in that chapter. In relation to the other capital expenditure adjustments, ElectraNet has incorporated all aspects of the AER's Draft Decision in its revised Revenue Proposal with the exception of those relating to:

- cost estimation risk factor;
- prudency adjustment to replacement and refurbishment projects;
- capex / opex trade-off;
- strategic land and easement acquisition costs; and
- load driven projects.

ElectraNet has also calculated updated values for materials escalation (as outlined in Section 3.3) and equity raising costs to reflect more recent information.

ElectraNet's response addressing each of the matters raised in the AER's Draft Decision where ElectraNet has not fully incorporated the revisions specified in the Draft Decision is included in the remainder of this chapter, with a revised capex forecast.

ElectraNet is confident that its revised capex forecast is both efficient and prudent and that it meets the capital expenditure objectives under the Rules.

Table 6-1 below sets out ElectraNet's response to the AER's Draft Decision by capex category.

Table 6-1: Summary of ElectraNet's response to Draft Decision by project category

Forecast capex category	ElectraNet response
Augmentation	Revised forecast submitted
Connection	Revised forecast submitted
Replacement	Revised forecast submitted
Refurbishment	Revised forecast submitted
Strategic land and easements	Revised forecast submitted
Security / compliance	AER approved Revenue Proposal estimate
Inventory / spares	AER approved Revenue Proposal estimate
Business IT	AER approved Revenue Proposal estimate
Building / facilities	AER approved Revenue Proposal estimate

6.2 Response to matters raised in the AER's Draft Decision

This section sets out ElectraNet's response to the AER's Draft Decision in respect of those matters raised by the AER with which ElectraNet disagrees.

6.2.1 Cost estimation risk factor

AER Draft Decision

In its Draft Decision, the AER approved the application of cost estimation risk factors in preparing capital project cost estimates, recognising the inherent asymmetric risk associated with estimating the cost of capital projects due to unforseen factors at the time of the initial estimate.

However, the AER did not approve ElectraNet's proposed cost estimation risk factor of 4.9 per cent, which was based on detailed analysis undertaken by Evans & Peck. The AER substituted the following cost estimation risk factors:

- 0 per cent for replacement and refurbishment projects;
- 2.6 per cent for augmentation and connection projects; and
- 2.6 per cent for all other capex.

The AER's Draft Decision appears to have been largely influenced by three key observations:

- "Given ElectraNet's focus on continuous improvement, the AER considers Evans & Peck's analysis is flawed by not taking into consideration… new cost estimating systems and processes" (page 123); and

- "The AER also considers it inappropriate to apply the same cost estimation risk factor to all capex categories, given more is known about a replacement than a new development. EMCa too considered estimate certainty is greater for replacement and refurbishment capex than for new augmentation and connection capex.[84] Replacements or refurbishments occur in environments that are known, so they do not encounter the uncertainty associated with a new project" (page 124).
- ElectraNet's "…cost estimation risk factor should not be above that from the AER's 2008 transmission determination" (page 124).

ElectraNet Response

ElectraNet does not accept that the substituted cost estimation risk factors applied by the AER are a realistic expectation of the cost inputs required by ElectraNet to achieve the capital expenditure objectives. Each issue raised by the AER above is addressed in turn below.

In order to assist the AER in its Final Decision, ElectraNet re-engaged independent expert Evans & Peck to provide a supplementary report addressing the issues raised by the AER. A copy of this advice is provided in Appendix H, and is summarised in the following sections.

<u>New cost estimating system risk</u>

The AER's Draft Decision reflects EMCa's conclusion that Evans & Peck did not take into consideration ElectraNet's new cost estimating system and that the magnitude of the cost estimation risk factor should reduce over time as the company improves its cost estimation processes. EMCa points to improvements that have been made in ElectraNet's cost estimating systems and processes as evidence to support the elimination of the risk allowance for replacement capital expenditure.

ElectraNet does not accept as correct EMCa's conclusion that the Evans & Peck analysis fails to take into consideration the improved accuracies of the new estimating system. Further, ElectraNet considers that EMCa has incorrectly assumed that these improvements will reduce asymmetric risk in project cost estimating.

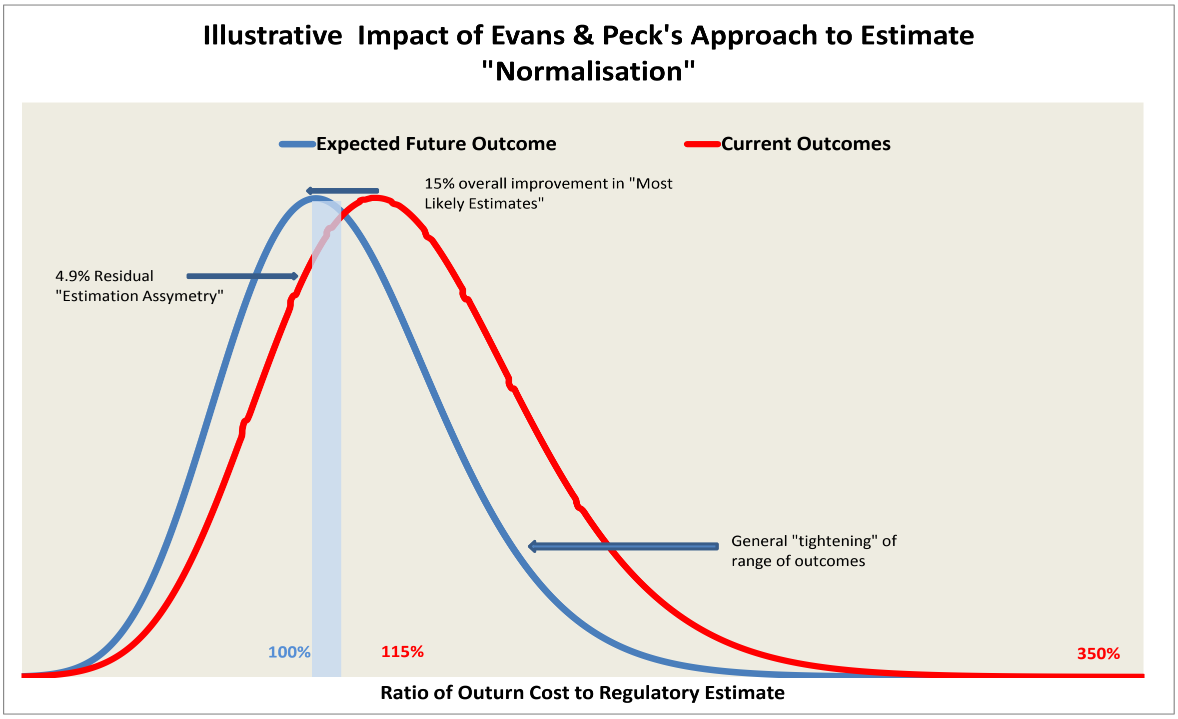
It is important to remember that the estimates used to construct the capex forecast are at a conceptual level for most projects in the forecast period. Detailed engineering designs, including site investigations have not yet been conducted. As such there exists significant risk in the estimates being used.

The statements by EMCa fail to recognise the theoretical basis of the calculations in the Evans & Peck analysis, which are based on "most likely" cost estimates for regulatory purposes. The fundamental assumption underpinning the theory of asymmetric risk is that the estimating system seeks to deliver the "most likely" base estimate.

Ongoing improvements in the accuracy of estimating processes that can be expected to occur over time will result in more reliable "most likely" cost estimates i.e. by reducing the range of uncertainty around the "most likely" estimate. Figure 6-1 demonstrates that this ongoing improvement has already been factored into the Evans & Peck analysis, and this is further explained in its supplementary report.

[84] EMCa, *ElectraNet technical review*, October 2012, page 82, paragraph 266.

Figure 6-1: Risks inherent in ElectraNet project cost estimation



Source: Evans & Peck, Capital Program Estimating Risk Allowance – Response to AER Draft Decision, January 2013 (refer Appendix H)

However, as shown above, asymmetric risk (i.e. the higher probability that actual outturn costs will be higher rather than lower compared to the "most likely" cost estimate) remains an inherent feature of large capital projects and cannot be avoided by improved estimating systems and processes. The only way to reduce this risk is if the scope and costing of projects is inflated to cater for unforseen or worst case outcomes. This result would be clearly inefficient and undesirable from a consumer perspective.

A failure to consistently achieve "best practice" "most likely" cost estimates in relation to its forecast capital projects therefore remains a residual risk to ElectraNet. As demonstrated in the Evans & Peck analysis, this risk is not compensated for in an ex-ante forecast, as required by the regulatory revenue setting process. This inherent risk is most efficiently addressed through a risk allowance which captures the average (i.e. diversified) risk across the portfolio, rather than building all potential risks into each estimate at greater overall cost. This is the approach that has been taken by Evans & Peck and should be accepted by the AER in its Final Decision as meeting the requirements of the Rules.

<u>Greenfield versus brownfield risk</u>

The AER's second observation in relation to lower risks associated with brownfield developments is not supported by analysis of ElectraNet's actual performance, or general industry experience.

Analysis of ElectraNet's actual costs in respect of capital projects over the current regulatory control period shows that whilst the differences are relatively small, brownfield projects have in fact performed worse than greenfield projects. This analysis is included in Appendix H.

There is an important distinction between where the risks have arisen. In the case of greenfield projects, the primary increases in cost have occurred as projects move from concept to final design, whereas the cost increases in brownfield projects tend to occur in the delivery phase.

Discussions with experienced contractors indicate that brownfield projects often encounter more issues in the delivery phase than greenfield projects due to unforseen factors such as working in “live” situations and the need to maintain functionality, unexpected below ground conditions and services (e.g. water, gas, telecommunications or similar) and the poor condition of existing structures when exposed and similar risks of this nature. There are many other variables and all projects carry risk, the reality is that there is no such thing as a project that carries no risk as there will always be external risks beyond the control or influence of ElectraNet.

Based on empirical evidence and operational experience, ElectraNet therefore rejects the AER’s conclusions relating to brownfield projects.

The AER should also be aware that a significant proportion of ElectraNet’s replacement capex forecast (about 40 per cent) is actually related to projects that are entirely greenfield developments (i.e. the replacement of a whole substation asset by a new one) rather than in situ replacement. Therefore, it the AER continues to argue that brownfield expenditure is lower risk than greenfield – which it is not – a further adjustment would need to be made to reflect the ‘greenfield component’ of replacement capex.

Risk factor applied in current period

The AER’s third observation is that the cost estimation risk factor should not be above the amount allowed in the 2008 determination. Implicitly, the AER’s view is predicated on two propositions:

- cost estimation should, if anything, achieve improved accuracy over time; and
- the cost estimation risk factor in the 2008 determination was correct.

In relation to the first proposition, it has already been noted that asymmetric risk is an inherent feature of large capital projects regardless of refinements or improvements to estimation techniques.

In relation to the second proposition, ElectraNet’s Revised Revenue Proposal in relation to the 2008 Determination argued that the AER’s cost estimation risk factor of 2.6 per cent in its Draft Decision should be increased to 4.6 per cent.[85] The AER did not accept ElectraNet’s proposed cost estimation risk factor and maintained its earlier view that 2.6 per cent was appropriate.[86] However, the actual data during the current regulatory period confirms that the 2.6 per cent allowance was inadequate. The relevant data and analysis is included in Appendix H.

85 ElectraNet, *ElectraNet Transmission Network revised Revenue Proposal 1 July 2008 to 30 June 2013*, 18 January 2008, page 30-33.

86 AER, *ElectraNet Transmission Determination 2008-09 to 2012-13: Final Decision*, 11 April 2008, page 52.

There is, therefore, no sound basis for the statement that the cost estimation risk factor should not be higher than 2.6 per cent. To conclude that the allowance provided for one period's risk factor ought to be no higher than the allowance provided in a former period, without taking into consideration whether the previous allowance was sufficient in that period and whether it is likely to be sufficient in the forthcoming period, is an unreasonable approach.

Comparisons with other businesses should also be approached with caution, given that cost estimation risk by its nature reflects the diversified risk inherent in a particular portfolio of capital projects, reflecting the circumstances of an individual business. ElectraNet notes for example that its capital program is a fraction of the size of the approved capital program of Powerlink (for which an allowance of 3.0 per cent was provided by the AER). It is reasonable to expect that a smaller capital program provides less opportunity to diversity risk and therefore requires a higher cost estimation risk factor. Given the reduction in size of ElectraNet's project portfolio in the forthcoming period, it is also reasonable to expect that a smaller capital program will have less diversity and a higher risk profile associated with it.

Conclusion

The AER's Draft Decision in relation to the cost estimation risk factor is based on a number of propositions that are not supported by the evidence. Historic analysis (especially when reinforced through scientific methods) of project cost data is the best method for determining an appropriate cost estimation risk allowance. On this basis, there is no sustainable reason for applying a risk factor that is different to the 4.9 per cent originally recommended by Evans & Peck in its May 2012 report.

The initial Evans & Peck analysis, now supported by its further supplementary analysis, clearly demonstrates that a 4.9 per cent cost estimation risk factor is appropriate for the circumstances faced by ElectraNet and reflects what is required to achieve the capex objectives under the Rules. Accordingly, ElectraNet has maintained its initial cost estimation risk factor in its revised Revenue Proposal.

6.2.2 Prudency adjustment

AER Draft Decision

The AER's Draft Decision imposes a prudency adjustment to all replacement and refurbishment projects over and above the capex efficiency factor included in ElectraNet's Revenue Proposal and approved by the AER (pages 121-122). The AER appears to have based this additional adjustment on:

- a view that ElectraNet has been overly cautious and not accounted for known efficiencies that are quantifiable now in its capex forecast (pages 124, 125); and
- EMCa's review of a representative sample of projects (pages 125, 126).

Based on EMCa's advice, the AER applied a 'prudency' adjustment of 7 per cent across all replacement and refurbishment projects in its Draft Decision. On this basis, the AER accepted the recommendation of EMCa to remove $31.7 million ($2012-13) from the replacement and refurbishment capex forecast.

The AER also formed the view that there is a high probability that efficiencies will be identified through the project management methodology (PMM) process given ElectraNet's sound cost estimation processes, though this has been provided for in the capex efficiency adjustment accepted by the AER.

EMCa sampled 8 out of a total of 61 replacement projects proposed by ElectraNet, and identified potential efficiency savings in 3 out of the 8 sampled projects. Specifically, the projects and issues identified by EMCa were as follows:

10619 Kincraig Substation Replacement

Potential savings of $5 million identified:

- replacement of 2 x 25MVA units with 2 x 60MVA units provides excessive capacity;
- retaining at least 1 refurbished transformer and deploying a new 25 MVA transformer could save $5 million, adding a third 25 MVA transformer as needed when demand exceeds capacity; and
- ElectraNet should also consider imposing a higher power factor level on SA Power Networks to defer the project.

11005 Kanmantoo Substation Upgrade

Potential savings of $5 million identified:

- no detailed condition assessment report has been provided justifying replacement;
- capacity increase not required until 2022, so the need for second transformer unclear;
- a 2nd transformer is not required under the ETC as a Category 1 exit point and could be deferred, saving $5 million; and
- ElectraNet should also consider imposing a higher power factor level on SA Power Networks to defer the project.

11890 Unit asset replacement

Potential savings of $1.5 million identified:

- no evidence has been presented that the asset replacements were identified through the asset management framework;
- no detail has been presented on how the $35 million cost was derived nor evidence that work schedules have been derived through asset data and analysis; and
- prudency gains in the order of at least 5 per cent (representing $1.5 million) are likely to be achievable through prioritisation and scope and cost firming.

ElectraNet Response

ElectraNet's capital expenditure estimates for the projects included in its capex forecast have been derived from its cost estimating systems and processes and represent "most likely" estimates, reflecting the latest information on external cost benchmarks and outturn costs experienced in the current regulatory control period for delivered projects. ElectraNet is unaware of any evidence that demonstrates that some unidentified future efficiencies are "quantifiable now".

Furthermore, experience in the current regulatory period indicates that "more likely" cost estimates have been underestimated by an average of 15 per cent, based on the risk analysis undertaken by Evans & Peck, indicating that overall efficiencies have not been delivered through scoping as claimed by EMCa and the AER. These learnings have been captured in ElectraNet's forecast cost estimates.

ElectraNet does not agree with EMCa's findings on the potential savings of 7 per cent across network replacement and refurbishment on the basis that EMCa's analysis underpinning this adjustment contains errors and inconsistencies. These errors and inconsistencies not only make EMCa's assessment of the potential savings in respect of each project incorrect, they demonstrate that the extrapolation of these apparent efficiency savings across the entire replacement and refurbishment programs is inappropriate.

<u>EMCa review of representative sample of projects</u>

The remainder of this section addresses the specific issues raised in relation to the 3 sample projects from which the 7 per cent prudency adjustment was calculated. It is noted that ElectraNet has previously provided this information to EMCa and the AER in order to assist in their assessment of these projects[87], but ElectraNet understands that time did not permit this information to be taken into consideration in the technical review and Draft Decision.

Of the two substation projects, it is also important to note that EMCa's conclusions relate to the augmentation component of each of these projects and not to replacement projects in general. Augmentation linked projects account for a small fraction of the overall replacement and refurbishment program, and these observations are therefore not generally applicable to the wider replacement forecast.

Each of the 3 sample projects are considered below in turn. Further detail on these projects is provided in the network project summaries contained in Appendix J.

<u>10619 Kincraig Substation Replacement:</u>

The delivery of the Kincraig substation replacement project has been deferred from the 2013-2018 regulatory control period. This deferral has arisen as a consequence of the change in demand forecasting methodology (use of 10 per cent probability of exceedance demand forecasts) and an agreement via joint planning with SA Power Networks to deploy a distribution capacitor, and has deferred the delivery date of this project to 2020.

Consequently, there is minimal spend associated with this project remaining in the next regulatory period and the claimed efficiency gains associated with this project are no longer applicable to the 2013-2018 capex forecast. However, for completeness, ElectraNet has addressed the underlying issues identified by EMCa.

87 ENET275, Response to proposed 7 per cent capex efficiency cut, 19 October 2012.

The replacement of Kincraig substation is driven by the condition of the assets at the substation, and the need for additional transformer capacity due to forecast demand growth. A detailed Transmission Asset Life Cycle (TALC) assessment has been undertaken, indicating that all major assets at this site are approaching end of life and therefore replacement of the substation is recommended. EMCa found that this assessment provides adequate justification for the replacement expenditure based on the age and condition of the assets.

Based on asset condition documentation, EMCa has assumed that it is economical for both existing transformers on the site to be refurbished, and that the newer of the two transformers is only 6 years old. This is incorrect.

Transformer 1 was manufactured in 1964. Detailed assessment indicates it is uneconomic to refurbish this transformer, and therefore it will be scrapped at the time of the Kincraig augmentation and replacement project (2020). Transformer 2 was manufactured in 1991, and will be 29 years old by this date. At the time of the augmentation, this transformer will be redeployed to Snuggery substation for efficient re-use at this site in accordance with ElectraNet's transformer redeployment plans.

ElectraNet has further considered potential transformer refurbishment options in light of the detailed transformer condition report for transformer 1 and the overall site condition. This would require:

- major overhaul of transformer 1 in the near term to extend asset life (considered risky based on detailed transformer condition assessment);
- the deployment of a spare transformer to site, and procurement of a replacement spare to maintain adequate spares inventory;
- deployment of the distribution solution in 2018;
- mid-life refurbishment of the second transformer to ensure comparable remaining expected life of 15 years to transformer 1;
- replacement of the substation in 2020 and installation of a third 25 MVA transformer; and
- subsequent replacement of the refurbished transformers at the end of extended technical life, and incremental maintenance.

The available options at the time of the required capacity increase that have been evaluated are:

- Option 1 - installation of a 9 Mvar 33 kV capacitor at SA Power Networks' Naracoorte substation in 2018 followed by deployment of Option 2 in 2020;
- Option 2 - replacement of the substation at an adjacent existing site (greenfield) with 2 x 60 MVA 132/33 kV transformers in 2018;
- Option 3 - replacement of the substation in situ (brownfield) with 2 x refurbished 25 MVA and 1 x new 25 MVA 132 / 33 kV transformers in 2018;
- Option 4 - replacement of the substation in situ (brownfield) with 3 x new 25 MVA 132 / 33 kV transformers in 2018; and
- Option 5 - 2 MW generation support deferral in 2018 followed by deployment of option 2 in 2020.

For completeness, ElectraNet has also undertaken further analysis to evaluate the option of refurbishing and reusing Transformer 2 together with two new 25 MVA 132 / 33 kV transformers. This would not result in materially different costs to Option 1, as this transformer is already intended for redeployment in the network and its continued use at this site would require the purchase of a replacement.

Table 6-2 below provides the results of the assessment considering the depreciated whole of life costs of the three options.

Table 6-2: NPV assessment of Kincraig options

Option	Description	NPV ($m)	Rank
1	Install a 9 Mvar 33 kV capacitor in 2018-19 followed by Option 2 in 2020-21	41.8	1
2	Install 2 new x 60 MVA transformers in 2018-19	47.5	3
3	Install 2 refurbished 25 MVA and 1 new x 25 MVA transformers in 2018-19	69.4	5
4	Install 3 new x 25 MVA in 2018-19	54.7	4
5	Hire 2 MW of generation in 2018-19 followed by Option 2 in 2020-21	44.8	2

The analysis demonstrates that the preferred option proposed by ElectraNet in its Revenue Proposal (and now deferred to 2020-21) remains the most efficient solution, while the option of transformer refurbishment is not considered economically viable.

ElectraNet notes that the project will also be subject to a comprehensive option assessment (during which issues such as power factor correction will be considered) and public consultation during the RIT-T process to ensure that the most efficient solution is delivered.

Based on the economic analysis summarised above, ElectraNet considers that EMCa's recommended solution of refurbishing one or more transformers as the preferred option to replacing the entire substation is uneconomical. Further, ElectraNet, believes that the $5 million efficiency EMCa claimed based on this proposed option does not exist. Therefore, the extrapolation of this hypothetical efficiency across the entire replacement and refurbishment program is also inappropriate.

<u>11005 Kanmantoo Substation Upgrade</u>

All replacement projects are identified through ElectraNet's asset condition monitoring and assessment framework. Accordingly, Kanmantoo substation replacement project has been subject to a full transmission asset lifecycle condition (TALC) assessment which identified the need for substation replacement. ElectraNet has supplied the AER along with this revised Revenue Proposal, a confidential TALC assessment for this substation.

The replacement of the Kanmantoo substation is efficiently timed to coincide with a requirement to increase transformer capacity. The capacity of the 3 MVA 11 kV loadable tertiary winding was forecast to be exceeded by 2016-17 (now 2017-18 under the revised demand forecasts) as outlined in the project summary for this project contained in Appendix P to the Revenue Proposal (May 2012).

In its review, EMCa concluded that the proposed 2 x 10 MVA transformer solution was in excess of the applicable reliability standard for Kanmantoo in the Electricity Transmission Code (ETC) and on this basis identified a potential $5 million saving to this project. The ETC currently classifies Kanmantoo as a Category 1 connection point, requiring at a minimum single transformer and single transmission line capacity to meet projected load.

ElectraNet's proposed solution is based on an economic assessment of the costs and benefits of increasing the reliability category of the Kanmantoo connection point from Category 1 to Category 2 through the addition of a second transformer. A Category 2 connection point must have duplicated transformer capacity equivalent to the projected load.

This analysis demonstrates that for a small incremental cost ($4.3 million) the net reliability benefits of this upgrade to customers in the area served by the substation exceed approximately $14 million through reduced interruptions to supply.[88]

AEMO considered this project in its assessment of ElectraNet's capital project forecast for the forthcoming regulatory period, which was concluded in June 2012.[89] AEMO acknowledged the reliability benefits estimated by ElectraNet of the proposed upgrade, noting that the analysis had been undertaken using the model and assumptions adopted by AEMO in its advice to ESCOSA in the review of the ETC in 2010.[90] Further correspondence has confirmed that AEMO is supportive of the upgrade on the basis of the estimated reliability benefits and incremental costs estimated by ElectraNet, and is supportive of the reclassification.

Whilst the standards of the ETC represent minimum standards, and nothing prevents a higher standard of reliability being delivered on an economic basis, in the interests of transparency, ElectraNet has proposed to ESCOSA that the reliability standard be explicitly reclassified in the ETC.

ElectraNet therefore proposed that the Kanmantoo Mine exit point should be assigned to reliability Category 2 under the ETC on and from 1 November 2017. ESCOSA is currently conducting a public consultation on this and other proposed changes to the ETC (with a final decision expected by the end of March 2013).[91]

88 Customer cost and benefits here refers to the value that customers place on lost load and is measured in terms of the probability of load being lost due to unplanned and planned outages. Refer to AEMO's analysis http://www.escosa.sa.gov.au/projects/165/review-of-the-electricity-transmission-code.aspx.

89 *ElectraNet Revenue Cap Review Capital Projects Assessment Report,* AEMO, 4 June 2012, http://www.aemo.com.au/en/Electricity/Planning/South-Australian-Advisory-Functions/ElectraNet-Revenue-Cap-Review.

90 *Review of the South Australian Electricity Transmission Code*, AEMO, 23 December 2010, http://www.escosa.sa.gov.au/library/101223-ReviewSAElectricityTransmissionCode-AEMO.pdf.

91 *Proposed Amendments to Revised Electricity Transmission Code*, letter from ElectraNet dated 26 November 2012, http://www.escosa.sa.gov.au/projects/190/electranet-s-proposed-amendments-to-revised-electricity-transmission-code.aspx.

Whether or not Kanmantoo Substation is reclassified to Category 2 in the ETC, ElectraNet's proposed solution has been demonstrated by an economic cost benefit analysis to be an efficient solution. EMCa's potential savings of $5 million are not prudent or efficient because it would deny customers the associated reliability benefits, which are estimated to be $14 million.

Furthermore, EMCa's assessment of the Kanmantoo Substation project cannot be considered as "statistically representative" of ElectraNet's broader replacement and refurbishment capital expenditure program given that the only concern raised by EMCa was that the project scope was more than is required to meet the minimum standards of the ETC and there are no other projects to which this concern is applicable. Therefore, EMCA's analysis cannot validly be used to infer inefficiency across the entire portfolio of replacement and refurbishment capex, even it EMCa's assessment were correct (which it is not).

<u>11890 Unit asset replacement</u>

The unit asset replacement project represents a unique program of targeted asset replacements, where such replacements cannot efficiently be undertaken in conjunction with broader replacement or augmentation projects. The principal benefit of this program is efficient asset life extension through replacement of individual components to manage risk, rather than wholesale asset replacement.

EMCa formed the view that this project was scoped at a high level and is likely to change significantly through the period, and on this basis concluded that prudency gains in the order of at least 5 per cent (representing $1.5 million) are likely to be achievable in the delivery of this program through prioritisation and scope and cost firming.

ElectraNet notes that this project has been scoped and costed on the basis of itemised substation assets (i.e. circuit breakers, voltage transformers, current transformers and protection relay sets) identified through the transmission asset life cycle (TALC) assessment process at the equipment type (or component) level within the overall asset management framework. This program has been designed specifically to address safety, reliability and availability issues at the component level.

The program has been compiled at specific sites across the network on a prioritised basis. Accordingly, ElectraNet rejects the inference that this is a high level or notional program.

Given the absence of any evidence to support EMCa's contentions, ElectraNet regards the claimed potential future efficiencies as speculative and unsubstatiated.

ElectraNet has supplied the AER along with this revised Revenue Proposal, a confidential report that provides full details of the assets to be replaced and their TALC assessment.

EMCa also observed that the project scope documentation included a reference to assets identified for replacement in substations associated with proposed contingent projects. Accordingly, ElectraNet has reviewed in detail the itemised listing of assets that comprise the unit asset replacement program. ElectraNet can confirm it has identified the following assets associated with contingent projects:

- a protection relay at Morphett Vale East substation – associated with the proposed Southern Suburbs Reinforcement contingent project (a project rejected by EMCa and the AER, now withdrawn); and

- a protection relay set at Yadnarie – associated with Lower Eyre Peninsula Contingent Project.

As noted by EMCa, if these contingent projects are activated, then these assets will be removed from the unit asset replacement project. The total value of these assets is approximately $0.1 million.

The cost estimates for the 2013-2018 period are derived from ElectraNet's established project cost estimating process, with the cost of individual components based on documented external information, and installation and other costs established from ElectraNet's experience of delivering similar unit asset replacements in the current regulatory period.

The scope and cost of this program reflect the best available information. Any further reduction in the costs of delivering this program based on as yet unidentified efficiencies is entirely speculative at this point. To the extent there are relevant efficiencies that should be appropriately factored into the forecasts, these have been included in ElectraNet's capex efficiency adjustment already accepted by the AER.

In the absence of any specific evidence on the scope for such efficiencies, it is invalid both to assume cost reductions in the order of 5 per cent for this project, and to extend this across the entire replacement and refurbishment forecast based on what is a unique project.

<u>Conclusion</u>

EMCa has proposed a 7 per cent reduction in ElectraNet's replacement and refurbishment program on the basis of efficiency gains that it considers available in respect of three projects. However, in relation to each of these projects ElectraNet has responded in detail to EMCa's concerns, demonstrating that the purported savings are not attainable, and cannot validly be applied more broadly across the replacement and refurbishment program:

- In respect of Kincaig substation, delivery of the project is now to be deferred beyond the forecast period as a result of adopting 10 per cent probability of exceedance demand forecasts. Furthermore, the claimed savings are based on the adoption of a solution ElectraNet has evaluated to actually be more expensive than the one proposed by ElectraNet.
- In relation to the Kanmantoo Substation Upgrade project, ElectraNet's proposed solution has been demonstrated by an economic cost benefit analysis to be an efficient solution. Furthermore, the current ETC consultation, if approved, will require the delivery of the economic solution identified by ElectraNet.
- The claimed savings in relation to the unit asset replacement program are speculative and unsubstantiated in nature. Furthermore, the unique nature of this project does not justify any wider application of efficiencies to unrelated projects in the capital program.

In light of the above errors and inconsistencies, ElectraNet does not believe any valid inefficiency has been demonstrated, nor does it believe the specific cases have identified any issues applicable in general to ElectraNet's replacement and refurbishment capital expenditure program. The proposed reduction would therefore not provide ElectraNet with a reasonable opportunity to recover its efficient costs.

6.2.3 SA Water replacement assets

AER Draft Decision

In its Draft Decision, the AER has approved ElectraNet's proposed replacement capex in relation to the SA Water pumping station assets. Despite this, the AER noted a number of concerns:

- clause 11.6.11 of the Rules provides for grandfathered connection arrangements if service levels remain unchanged, and protects SA Water from a potential increase in its charges. This clause appears to prevent an incentive to promote prudent and efficient replacement capex decisions, and should be reviewed;
- there is an apparent lack of justification for like-for-like replacement of these assets as an efficient solution, and strategic planning of water and electricity assets could provide a more optimised approach to replacement of these assets; and
- the AER has no scope to make adjustments to ElectraNet's proposal, given the grandfathering arrangements of clause 11.6.11 of the Rules.

ElectraNet Response

ElectraNet agrees with the AER's decision to include the proposed replacement expenditure in its capex forecast, and makes the following observations:

- The need for the replacement of these substations is accepted by both the AER and its consultant on the basis of the assessed condition of these assets;
- SA Water has confirmed its ongoing service requirements at these sites remain unchanged based on its long-term water pumping requirements at these locations to support South Australia's water supply;
- ElectraNet is required to comply with the grandfathering provisions of clause 11.6.11 of the Rules (and any potential future change to this clause is clearly beyond the scope of this revenue determination); and
- On the information available to it on revealed asset condition, assessed risk and confirmed ongoing service requirements, ElectraNet believes the proposed replacement of these substations to be a prudent and efficient asset replacement decision.

6.2.4 Strategic land and easement acquisition costs

AER Draft Decision

In its Draft Decision, the AER agreed that strategic land and easement acquisitions can be appropriate. However, it did not approve ElectraNet's proposed strategic land and easement forecast of $65.8 million ($2012-13). The AER considered it likely that some level of strategic purchases can be justified in the upcoming regulatory control period, and accepted an indicative substitute forecast of $13.4 million ($2012-13) based on recommendations made by its consultant EMCa.

The following factors appear to have been most influential in making this decision:

- the significant increase in forecast strategic land and easement capex compared to historical expenditure (page 129);

- that AER's view that ElectraNet has not given sufficient weight to the protections afforded by planning instruments such as the 30-Year Plan for Greater Adelaide, noting that council designations over regional level land use policies provide reasonable expectations that competing land users will not encroach on the designated land area (page 133); and
- the forecast capex was not supported by a satisfactory cost-benefit analysis to assess the risks of delaying each proposed acquisition compared to the estimated carrying costs of the land acquisition (page 129).

ElectraNet Response

ElectraNet does not accept that the AER's reduced allowance for strategic land and easement acquisition in the forthcoming regulatory control period reflects the prudent and efficient costs required to achieve the capex objectives.

ElectraNet responds to each of the issues identified by the AER above in turn.

<u>Significant increase in forecast capex</u>

One of the defining characteristics of transmission networks is the lumpy nature of capital and operating expenditure requirements (especially compared to distribution networks). This is a key reason why trending forward historical costs without adequate consideration of changes in cost drivers risks providing an inappropriate expenditure allowance and, therefore, inefficient outcomes.

The key change driver leading to a higher proposed forecast for strategic land and easement capex is the projected need for several major transmission line projects in the future. The transmission projects are driven both by emerging asset replacement requirements based on condition and risk, and by ongoing load growth which will see the network exceed its capacity at a number of locations, despite ongoing efforts over many years to defer major line augmentation as long as economically possible.

The simple fact that forecast capex is higher than historical levels does not mean that the higher expenditure is not needed or inefficient. A forecast that represents a significant departure from a historical trend may be a reason to focus in on that particular matter and to examine why there is such a change, but there should not be a presumption that a significant change suggests inefficient expenditure. That is, the fact that a forecast is significantly higher than a past trend is not a valid reason for not approving that forecast.

Nevertheless, ElectraNet has reviewed the 20 strategic land and easement acquisitions originally proposed in light of the revised demand forecasts[92] on which the capex forecast of the revised Revenue Proposal is based.

ElectraNet's review of the strategic land and easement acquisitions has revealed that the likelihood of a number of land and easement acquisitions being required in the 2013-2018 regulatory period has reduced as a consequence of the lower demand forecasts. The number of proposed acquisitions ElectraNet includes in this revised Revenue Proposal has reduced to 6 (noting that the reduction in the capex forecast is proportionally less than the reduction in the number of projects).

The projects which comprise the revised proposed strategic land and easement acquisition forecast are listed in Table 6-3.

92 The revised demand forecasts are discussed in Chapter 4 of this revised Revenue Proposal.

Table 6-3: Revised proposed strategic land and easement acquisition projects ($m 2012-13)

Project	Cost
11383 Mt Barker Triple Circuit Easement Expansion	4.4
11738 Mallala to Para 275kV Double Circuit Land & Easements	9.1
11739 Templers to Para 275kV Double Circuit Land & Easements	7.2
11132 Fleurieu Peninsula Strategic Land and Easement Acquisition	7.4
11630 Eyre Peninsula Reinforcement - Land Acquisition	10.7
11461 Cultana to Stony Point Easement	0.9

Protections afforded by planning instruments

In its Draft Decision, the AER observes:

> "Connor Holmes recommended that all 21 of the proposed acquisitions should be made in the 2013-2018 regulatory control period. ElectraNet appears to have accepted this advice and implemented an approach that considers purchasing land and easements to be the only strategic option. EMCa concluded that this is not prudent or efficient. Rather, all other regulatory and legislative options should be pursued before the expense of making a strategic acquisition can be justified. ElectraNet has done this to some extent by obtaining planning instruments on 11 occasions. However, it has not given sufficient weight to the protections that they afford and proposed an overly cautious land and easement capex."[93]

The EMCa conclusion referred to above appears to be largely based on a misunderstanding of the land use planning system in South Australia. ElectraNet engages very actively with the Department of Planning, Transport and Infrastructure and other authorities in strategic land use planning for South Australia. However, it is important to note that the planning system, while giving assurances on land use policy, cannot guarantee development rights unless ElectraNet acquires the necessary easements for a line corridor.

While ElectraNet is formally engaged at the development plan amendment (DPA) stage, it can only provide comment and seek to influence outcomes. At the DPA stage, ElectraNet cannot secure provisions to be made through the state strategic land use planning system for future power line corridors and major substation sites. ElectraNet has no formal legal authority within the South Australian land use planning system, which is only afforded to Government departments, agencies and corporations.

As confirmed by the Deputy Chief Executive of the Planning Division, Department of Planning, Transport and Infrastructure:

> "It is important to note that the planning system, whilst giving assurances on land use policy, cannot guarantee development rights unless ElectraNet acquire the corridor."[94]

This means that having proposed transmission developments recognised and corridors for these included in planning instruments such as the 30-Year Plan for Greater Adelaide is of no value in terms of securing easements. While this recognition in planning instruments is useful for influencing future land use zoning and reducing the risks of incompatible

93 AER, Draft Decision, page 233.

94 Correspondence from the Deputy Chief Executive of the Planning Division, Department of Planning, Transport and Infrastructure dated 1 November 2012, Appendix I.

development of land adjacent proposed future transmission line corridors, these measures effectively provide no protection for securing the necessary easements when needed.

In the absence of any legislation giving ElectraNet preserved sites and corridors for future transmission network development, it is imperative that ElectraNet acquires key substation sites and easement corridors where there is a high risk of being effectively 'locked out' of future access through changes in surrounding land use.

Cost-benefit analysis

ElectraNet has reviewed the strategic land and easement acquisition projects in response to the concerns expressed by the AER. The decision to strategically acquire land or easements depends on a number of influencing factors. These include but are not limited to; future availability, length of the negotiating period, sensitive environmental issues, and time needed to obtain development and other statutory approvals. ElectraNet has set out with this revised Revenue Proposal the full business case evaluation for each of the projects which comprise the revised proposed strategic land and easement capex forecast. These business cases are contained Appendix I.

6.2.5 Load driven projects

AER Draft Decision

In its Draft Decision, the AER did not approve ElectraNet's proposed capital expenditure forecast as reflecting a realistic expectation of demand. The AER instead substituted its own demand forecast, as provided by EMCa / NZIER, and adopted a substituted capex forecast.

The substituted capex forecast included the deferral of $103.7 million ($2012-13) in load driven capex, including the deferral of approximately nine new augmentation and connection projects by three years and the deferral of three large replacement projects with an augmentation component for a similar period. EMCa noted that its assessment was being made 'in the absence of more refined information'.

In applying these adjustments, the AER accepted the advice of its consultant that a considerable portion of ElectraNet's connection and augmentation capex is not driven by demand growth, and that projects already commenced with commissioning dates in 2013 or 2014 could not be deferred.

ElectraNet Response

The load driven capex forecast proposed in ElectraNet's Revenue Proposal (May 2012) reflected maximum peak demand forecasts at a connection point level provided by SA Power Networks and direct connect customers, and AEMO's 2011 state-wide medium growth 10 per cent probability of exceedance demand forecasts. As explained in its Revenue Proposal, ElectraNet uses the AEMO forecasts to plan main grid augmentations, and applies connection point forecasts to connection point and regional network planning.[95]

As discussed in Chapter 4, ElectraNet does not accept the AER's substituted demand forecast, and has adopted revised demand forecasts for the purposes of this revised Revenue Proposal comprising:

95 2013-2018 ElectraNet Revenue Proposal, page 64.

- The 2012 state-wide forecasts published by AEMO; and
- Revised connection point forecasts based on advice from SA Power Networks and the adoption of a 10 per cent probability of exceedance demand forecast for connection points ETC Category 2 and above.

The load driven capex program ElectraNet put forward in its Revenue Proposal did not contain any main grid augmentation requirements. Consequently, the adoption of the 2012 AEMO state-wide forecasts (which have fallen significantly relative to its 2011 forecasts) did not contribute any projects to ElectraNet's revised proposed load driven capex program.

The adoption of the revised connection point forecasts has resulted in the deferral of significant load driven investment from the 2013-2018 forecast period. The overall reduction in the load driven capital program for the period is about $130 million ($2012-13) as detailed in Table 6-4 below. Of this $113 million ($2012-13) is directly attributable to the adoption of the revised 10 per cent probability of exceedance connection point demand forecasts.

Table 6-4: Reduction in load-driven capex in the 2013-2018 regulatory period ($m 2012-13)

Project	Category	($m)
Kincraig Substation Replacement and Transformer Upgrade	Replacement	-39.2
East Terrace Second Transformer	Connection	-23.2
Keith Substation Rebuild	Replacement	-18.6
Mount Barker South 275-66kV Transformer	Connection	-8.9
Bungama Second Transformer	Augmentation	-8.1
Blanche 15MVar Capacitor Bank	Augmentation	-4.9
Penola West 15MVar Capacitor Bank	Augmentation	-3.4
Monash Capacitor Bank	Augmentation	-3.2
Torrens Island Transformer Upgrade	Augmentation	-2.0
Kadina East 132KV Capacitor Bank	Augmentation	-1.3
Net impact of other project timing movements from the period	Connection / Augmentation	-18.9
Total		**131.7**

The consequential impacts of this deferral in network investment include minor incremental maintenance requirements (as detailed in Chapter 7) and the replacement of minor assets under the unit asset replacement project as follows:

Keith Substation ($1.09 million)

- 3 x sets protection panels;
- 1 x circuit breaker;
- 1 x set capacitive voltage transformers; and

- 3 x sets current transformers.

ElectraNet has therefore not accepted the AER's substituted load driven capex forecast, and has adopted a revised proposed load driven capex forecast that corresponds with ElectraNet's probabilistic demand forecasts. ElectraNet's revised capex forecast is presented in Section 6.3 below.

6.3 Revised Forecast Capital Expenditure

This section presents ElectraNet's revised capex forecast for the 2013-2018 regulatory control period. The revised forecast is the result of applying the adjustments described earlier in this chapter to the AER's Draft Decision.

ElectraNet's revised capex forecast of $748.3 million is $145.8 million (16 per cent) lower than the May 2012 Revenue Proposal of $894.1 million and represents a $99.1 million (12 per cent) reduction over the current period spend. The majority of this decrease is directly attributable to adoption of the 10 per cent probability of exceedance connection point demand forecast described in Chapter 4.

6.3.1 Equity raising costs

AER Draft Decision

The AER approved ElectraNet's method for determining its benchmark equity raising cost allowance associated with its forecast capex.

The AER has updated ElectraNet's proposed equity raising cost allowance to reflect the Draft Decision RAB roll forward and indicative WACC determined by the AER. The AER also indicated it would update the proposed equity raising cost allowance for its Final Decision.

ElectraNet Response

ElectraNet has applied the calculation method approved by the AER to update its proposed equity raising cost allowance in this revised Revenue Proposal, consistent with its revised proposed capex forecast.

6.3.2 Materials escalation

AER Draft Decision

The AER approved ElectraNet's method for determining its materials escalation via a weighted average material escalator. The AER has updated ElectraNet's proposed materials escalation to reflect more recent available information, as outlined in Chapter 3. The AER also indicated it would update the inputs closer to its final decision.

ElectraNet Response

ElectraNet has applied the calculation method approved by the AER to update its proposed materials escalation in this revised Revenue Proposal, consistent with its revised proposed capex forecast.

6.3.3 Summary of revised forecast

ElectraNet's revised capital forecast is shown by category in Table 6-5 below.

Table 6-5: Capital expenditure forecast by category ($m, $2012-13)

Capital Expenditure by Category	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Augmentation	38.0	11.4	10.7	12.7	15.3	88.3
Connection*	39.0	17.4	17.8	10.6	3.8	88.5
Replacement	86.5	66.6	71.9	81.6	36.6	343.2
Refurbishment	1.1	6.2	29.5	14.7	2.1	53.6
Easement/Land	12.1	20.5	5.6	1.3	0.0	39.6
Security/Compliance	17.8	13.9	14.5	10.9	8.1	65.3
Inventory/Spares	5.3	3.8	4.7	3	2.1	18.9
Total network	**199.9**	**139.9**	**154.7**	**134.7**	**68.1**	**697.4**
Information Technology	10.4	10.8	11.4	7.2	5.5	45.3
Facilities	0.7	1.5	2.1	0.6	0.6	5.6
Total non-network	**11.1**	**12.2**	**13.6**	**7.9**	**6.1**	**50.9**
Total	**211.0**	**152.1**	**168.3**	**142.6**	**74.2**	**748.3**

* Includes the remaining balance of the capital expenditure for the Munno Para contingent project allowance of $34 million previously approved by the AER, as required under clause 6A.6.7 of the Rules.

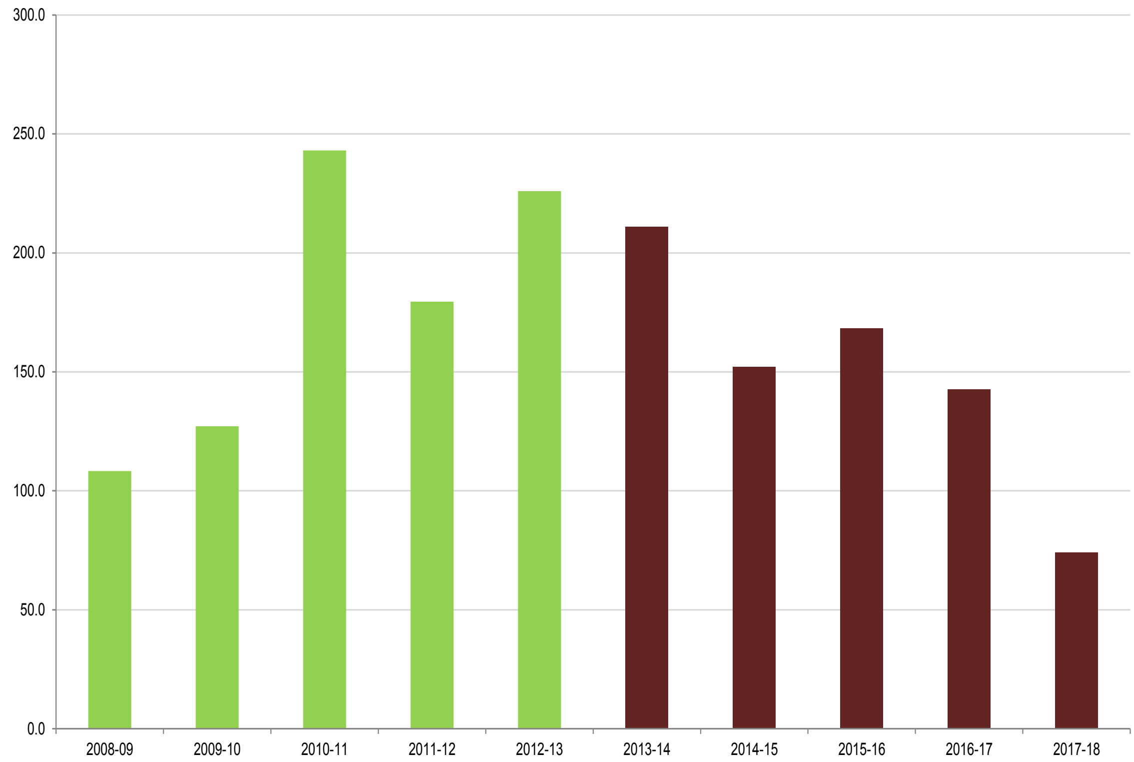
Table 6-6 compares the revised capex forecast with the AER's Draft Decision showing incremental changes from the Draft Decision.

Table 6-6: Revised capex forecast comparison ($m 2012-13)

Adjustment	2013-14	2014-15	2015-16	2016-17	2017-18	Total
AER Draft Decision	**183.2**	**120.3**	**141.0**	**122.4**	**75.0**	**641.9**
Adjustment to cost estimation risk factor	1.7	2.2	4.3	4.3	2.1	**14.6**
Adjustment to prudency adjustments	5.2	4.6	6.1	5.9	2.0	**23.8**
Adjustment to capex / opex trade-off[96]	10.1	10.0	10.0	10.0	10.0	**50.1**
Adjustment to strategic land and easement acquisition program	6.2	26.4	4.4	(1.1)	(7.5)	**28.4**
Adjustment to load driven projects	5.7	(10.3)	2.3	(0.6)	(8.7)	**-11.6**
Escalation	(1.1)	(1.1)	0.3	1.6	1.3	**1.0**
Revised Revenue Proposal	**211.0**	**152.1**	**168.4**	**142.5**	**74.2**	**748.3**

Figure 6-2 below compares the revised annual capital expenditure forecast with the total annual historical capital expenditure in the current regulatory period.

Figure 6-2: Current period versus revised forecast capital expenditure ($m 2012-13)



96 Refer Chapter 5.

For completeness, Appendix J contains amendments to the project summaries included in ElectraNet's Revenue Proposal (May 2007) to reflect the changes in timing of those projects impacted by the adoption of the revised demand forecasts.

ElectraNet has also completed the required pro forma historical and forecast capital expenditure templates, which accompany this revised Revenue Proposal.

6.3.4 Consistency with AEMO's NTNDP

The Rules require that the revised Revenue Proposal include a statement as to whether it is consistent with the most recent NTNDP.[97]

Section 5.9.1 of ElectraNet's Revenue Proposal (May 2012) included a statement of consistency with AEMO's 2011 NTNDP,[98] based on the development of ElectraNet's network capital expenditure plans in consultation with AEMO.

The 2012 NTNDP[99] concludes that there are no limitations involving the main transmission network for the planning outlook period in the three primary network zones assessed for national transmission planning purposes in South Australia, namely the Adelaide, Northern South Australia and South East South Australia zones. ElectraNet's revised proposed capital expenditure forecast does not contain any main grid augmentation projects.[100]

The NTNDP also contains a listing of augmentation projects as published in ElectraNet's 2012 Annual Planning Report. The majority of these projects are considered by AEMO to be beyond the scope of the NTNDP. Of the remainder, only those projects that address limitations identified in the 2012 NTNDP expansion plan are included in the revised proposed ex ante forecast.

On this basis, ElectraNet considers that this revised Revenue Proposal is consistent with the 2012 NTNDP.

6.3.5 Directors' responsibility statement

In accordance with clause S6A.1.2(6) of the Rules, this revised Revenue Proposal must contain a certification of the reasonableness of the key assumptions that underlie the capital expenditure forecast by the Directors of ElectraNet.

The Directors' Responsibility Statement is included in Appendix A.

97 Clause 6A.10.1(f) of the Rules.

98 *National Transmission Network Development Plan*, AEMO, December 2011.

99 *National Transmission Network Development Plan*, AEMO, 11 December 2012.

100 As noted in the 2012 NTNDP (page 3.24) ElectraNet and AEMO are party to a joint Regulatory investment Test for Transmission (RIT-T) application to investigate an increase in the capacity of the Heywood interconnector, which is included in this revised Revenue Proposal as a contingent project.

7. Operating Expenditure

7.1 Summary

Chapter 6 of ElectraNet's Revenue Proposal (May 2012) sets out the methodology, key inputs and assumptions used to determine the operating expenditure forecast for the next regulatory control period.

As explained in ElectraNet's Revenue Proposal, ElectraNet faces a significant increase in its operating expenditure resulting from increased asset management requirements that have emerged during the latter half of the current regulatory control period, based on the following cost drivers:

- a growing asset base to meet increased customer demand requires higher levels of operating expenditure (net of scale efficiencies);
- continued implementation of a best practice asset management framework to encompass all network assets and manage the increased level of network risk revealed through improved asset condition information;
- the drive to improve asset utilisation, maximise network performance and capability in order to defer the need for capital investment and deliver lowest long-run cost solutions;
- real wages growth and related cost pressures caused by a projected strengthening in employment demand in the mining and construction sectors in South Australia; and
- a number of scope changes and new regulatory obligations imposing additional costs on the business.

The AER in the Draft Decision did not approve ElectraNet's proposed total operating expenditure forecast of $478.1 million ($2012-13) for the 2013-2018 regulatory control period. The AER considered that ElectraNet's forecast did not reasonably reflect a realistic expectation of the cost inputs required to achieve ElectraNet's operating expenditure objectives.

In its Draft Decision, the AER:

- adopted a substitute operating expenditure forecast of $397.6 million ($2012-13) developed from a top down revealed cost approach, and limited step changes to reflect ElectraNet's changing business environment (page 138);
- did not approve network optimisation as a new operating expenditure category and rejected the forecast allowance of $13.3 million ($2012-13) (page 147);
- did not approve the use of year 4 (2011-12) as the base year as the AER considered that 2011-12 is not a year reflective of typical recurrent costs and substituted year 3 (2010-11) as an efficient recurrent base year for deriving the opex forecast, with adjustments to remove movements in provisions and regulatory compliance costs (page 152);
- approved the annualised cost of a lease entered into during 2011-12, but did not approve an additional accommodation requirement from 2014-15 (page 284);

- applied a reduction to the opex forecast of $4.9 million ($2012-13) to account for the announced intention of the South Australian Energy Minister to reduce the annual transmission licence fee payable by ElectraNet (page 284);
- did not approve ElectraNet's method for estimating asset growth, and substituted revised asset growth factors (page 153);
- did not approve ElectraNet's proposed economies of scale factors, and substituted revised estimates (page 153);
- did not approve ElectraNet's real cost escalators, and substituted revised estimates (page 154);
- applied an opex efficiency reduction of 2.5 per cent to the base year (and therefore to the opex forecast) on the grounds that the base year opex does not capture the removal of all current and existent inefficiencies (page 154);
- approved ElectraNet's routine maintenance forecast of $80.9 million ($2012-13) (page 156);
- did not approve ElectraNet's corrective maintenance forecast of $68.8 million and adopted a substitute forecast of $43.7 million ($2012-13) on the basis of historic cost (pages 157-158);
- did not approve ElectraNet's operational refurbishment forecast of $64.9 million and adopted a substitute forecast of $47.0 million ($2012-13) on the basis of historic cost (page 158, 159);
- did not approve ElectraNet's forecast for the following expenditure categories based on a 2011-12 base year, and substituted forecasts for these expenditure allowances using 2010-11 as the base year (page 159) as follows:
  - the asset manager support forecast of $43.8 million was not approved, and a forecast substitute of $51.7 million ($2012-13) was used (page 140);
  - the maintenance support forecast of $69.9 million was not approved, and a forecast substitute of $48.6 million ($2012-13) was used (page 140);
  - the corporate support forecast of $33.8 million was not approved, and a forecast substitute of $31.4 million ($2012-13) was used (page 140);
  - the network operations forecast of $47.3 million was not approved, and a substitute forecast of $40.2 million ($2012-13) was used (page 140);
- did not approve ElectraNet's forecast for land tax payments of $14.7 million, and substituted an estimate of $11.8 million ($2012-13) (page 159);
- did not approve ElectraNet's insurance forecast of $15.1 million, which was based on an expert estimate, and substituted an estimate of $13.0 million ($2012-13) based on historic cost (page 160);
- approved ElectraNet's self-insurance forecast of $6.8 million ($2012-13) as revised by ElectraNet to reflect its reduced risk profile following the approval of a Rules change enabling ElectraNet to nominate additional cost pass through events[101] (page 161);
- approved ElectraNet's network support forecast of $41.6 million ($2012-13) (page 161);

[101] AEMC, Rule determination, *National electricity amendment (cost pass through arrangements for network service providers) Rule 2012,* 2 August 2012.

- approved ElectraNet's method for determining benchmark debt raising costs, and revised ElectraNet's estimate from $6.3 million to $5.8 million ($2012-13) to account for the AER's revised RAB forecast (page 163);
- did not approve ElectraNet's proposed step change of $2.4 million ($2012-13) to cover the projected shortfall in defined benefits scheme superannuation contribution payments (page 286); and
- presented benchmarking analysis as evidence of ElectraNet's relative opex performance (Appendix B).

In addition to the above matters, the AER argued that ElectraNet had not sufficiently factored the expected benefits of its asset management framework into its regulatory proposal. In Chapter 5, ElectraNet addressed the AER's proposed the capex-opex trade-off adjustment to account for these benefits, which ElectraNet strongly rejects. This matter is not considered further in the remainder of this chapter.

In light of the adjustments listed above, ElectraNet is very concerned that the AER Draft Decision does not provide ElectraNet a reasonable opportunity to recover its efficient costs.

As summarised in Table 7-1, ElectraNet has incorporated some aspects of the AER's Draft Decision, but cannot accept the AER's forecasts in respect of the following opex categories:

- corrective maintenance;
- operational refurbishment;
- network optimisation;
- maintenance support;
- network operations;
- asset manager support;
- corporate support; and
- debt raising costs.

Table 7-1 Summary of ElectraNet response to AER Draft Decision opex forecast

Opex Category	ElectraNet response
Routine maintenance	AER Draft Decision amount incorporated
Corrective maintenance	Revised forecast submitted
Operational refurbishment	Revised forecast submitted
Network operations	Revised forecast submitted
Network optimisation	Revised forecast submitted
Maintenance support	Revised forecast submitted
Asset manager support	Revised forecast submitted
Corporate support	Revised forecast submitted
Self-insurance	AER Draft Decision amount incorporated
Network support	AER Draft Decision amount incorporated
Debt raising costs	Revised forecast submitted

In submitting the revised estimates shown above, ElectraNet has not incorporated the following aspects of the AER's Draft Decision because it does not agree that these elements of the Draft Decision are consistent with the requirements of the Rules and the Law:

- movements in provisions;
- opex efficiency adjustment;
- superannuation shortfall payments;
- insurance forecast;
- asset growth factors;
- scale efficiency factors; and
- real cost escalation.

The following sections address each of these matters raised in the AER's Draft Decision, together with a revised opex forecast on the basis that the AER's Draft Decision does not provide ElectraNet a reasonable opportunity to recover its efficient costs.

ElectraNet's considers its revised opex forecast is both efficient and prudent and meets the operating expenditure objectives.[102]

7.2 AER's top down assessment

AER Draft Decision

The AER did not approve the operating expenditure forecasting approach adopted by ElectraNet, involving both top down and bottom up expenditure components, as an appropriate means of forecasting ElectraNet's expenditure requirements for the next regulatory control period.

[102] Rules, clause 6A.6.6.

The AER substituted ElectraNet's controllable operating expenditure forecast with a forecast using a top down or base-year extrapolated approach. The top down forecast is based on determining an "efficient year" that reflects ElectraNet's "revealed costs". The forecast opex is then extrapolated from this base year. The AER then applied step changes to adjust the forecast for efficiency improvements and changes in ElectraNet's business environment and circumstances that were not accounted for in the base year.

ElectraNet's Response

ElectraNet does not accept the AER's top down approach to developing the operating expenditure forecast is reasonable or appropriate to ElectraNet's circumstances.

The base-year "revealed cost" model (or revenue cap and EBSS) provides an incentive to achieve an efficient level of expenditure in any year, with this incentive constant throughout the regulatory period. As the AER has recognised, knowledge of the efficient level of expenditure in the base year provides a robust starting point for the forecast of operating expenditure for the next regulatory period.

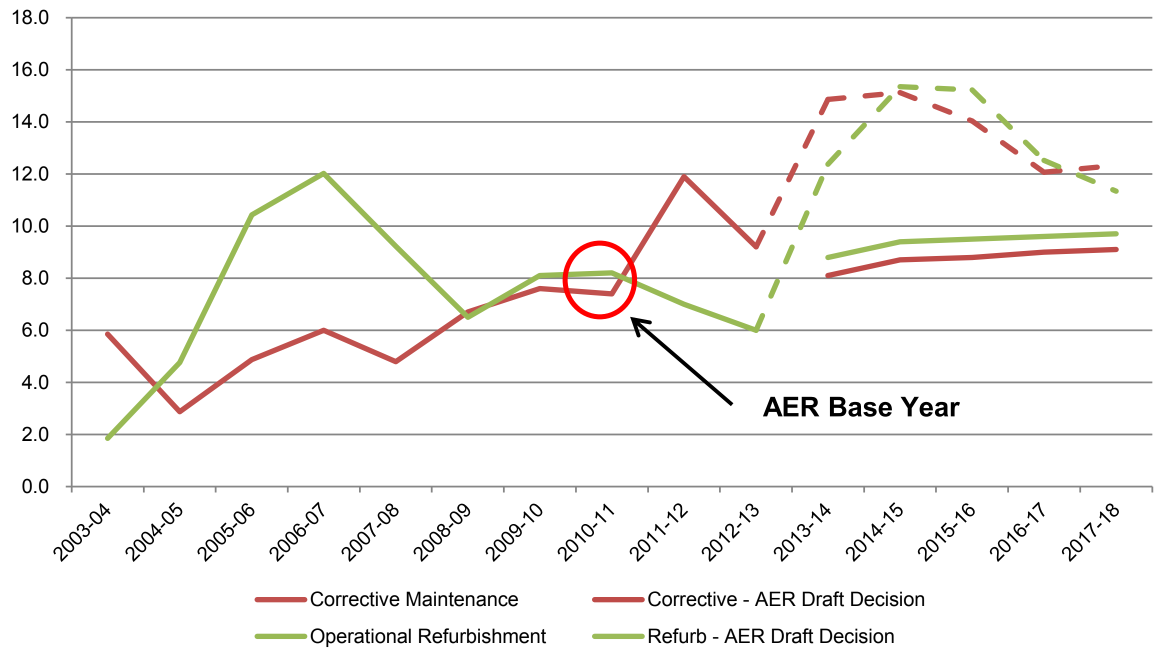
However, the "revealed cost" model will only provide TNSPs with "a reasonable opportunity to recover at least efficient cost" – as set out in the revenue and pricing principles in the National Electricity Law – if the resulting forecast of operating expenditure takes account of the forecast variation in operating expenditure over time, compared to the base year.

Where the efficient volume of activities or works for key categories of expenditure vary materially over time – as is typically the case for transmission – then it is essential for the expenditure forecasts to take account of that forecast variation.

There is no such thing as a "revealed cost trend" that can be projected – if opex is lumpy – for example, because the volumes of required operational refurbishment projects vary over the period – then a forecast that reflects the expected lumpy expenditure is required. It is not enough to simply say that the expenditure in the base year will provide a sufficient allowance if the volumes of work change materially from year to year. Equally, it is invalid to assert that lumpy items are "one off" events that should be excluded from any trend. "One off" or lumpy expenses are incurred and therefore need to be recognised.

Figure 7-1 demonstrates the inherent lumpy nature of corrective maintenance and operational refurbishment in the current regulatory control period.

Figure 7-1 Comparison of forecast and historical maintenance expenditure ($m 2012-13)



The base year chosen by the AER is clearly not representative of the overall maintenance expenditure profile.

The lumpy nature of required transmission expenditure is a key reason why trending forward historical costs without adequate consideration of changes in cost drivers risks providing an inappropriate expenditure allowance and, therefore, inefficient outcomes. Specifically, a failure to have regard to underlying cost drivers and whether they are accounted for in the base-year risks determining an expenditure level that is inconsistent with the *national electricity objective* and the revenue and pricing principles, in particular, the principle that a TNSP be provided with a reasonable opportunity to recover at least the efficient costs the TNSP incurs in providing direct control services.

ElectraNet notes that the more variable nature of transmission expenditure drivers was previously accepted by the AER in its 2008 determination, which found that the forecasting methodology applied by ElectraNet: [103]

> "…provided a sound basis for determining the efficient opex required by a prudent operator in the circumstances of ElectraNet. The methodology provided for extrapolation of base year costs for some components of opex and the derivation of bottom up (zero base) cost estimates for other components. Zero based estimates were accepted where the base year expenditure either did not exist or did not reflect likely future expenditure patterns for that opex component.
>
> The AER considers that the hybrid approach proposed by ElectraNet and accepted by the AER represents the most appropriate means of forecasting ElectraNet's opex for the next regulatory control period."

[103] AER, *"ElectraNet Transmission Determination 2008-09 to 2012-13 – Final Decision,"* 11 April 2008, page 74.

A particular concern with the AER's forecasting approach relates to the operating expenditure forecasts arising from the new asset management regime. ElectraNet's asset management regime was endorsed by the AER in its determination for the 2008-2013 regulatory period: [104]

> "…the adoption and implementation of the new asset management and maintenance regime is a prudent action by ElectraNet, which should result in a better understanding of its network and better maintenance practices."

ElectraNet has now completed the first cycle of substation condition assessments. However, completion of the first cycle of transmission line condition assessment is not expected until the end of the 2013-2018 regulatory period and is currently only 40 per cent complete. As such, the revealed asset risk is not at steady-state, and therefore base-year extrapolated forecasts for these opex components will not be reflective of expected expenditure requirements in the next period.

In this regard, ElectraNet notes the AER's description of 'step changes' in its Draft Decision:[105]

> "The extrapolated costs can be adjusted for any 'step changes' as necessary. Step changes allow additional funding where the service provider faces a new requirement or change in circumstance requiring it to undertake additional expenditure that was not accounted for in the base year. Examples of step changes are new safety regulations or new maintenance projects."

ElectraNet regards the risks revealed through the asset condition information flowing from the ongoing implementation of its new asset management regime as constituting a change in circumstance, and therefore the associated operating expenditure should be regarded as a step change. As already noted, the overarching objective is to ensure that the resulting operating expenditure allowance satisfies the requirements of the Rules and the National Electricity Law.

The AER's Draft Decision contends that ElectraNet is operating in a steady state environment and that ElectraNet's own forecasting method supports a revealed cost approach: [106]

> "ElectraNet's asset management strategy is aligned over three regulatory periods: 1 January 2003 to 30 June 2008, 2008–2013 and 2013–2018. This alignment suggests a link between revealed costs and forecast costs. ElectraNet is developing its asset profiles, which will be completed half way through the 2013–2018 regulatory control period (for transmission lines). It thus based its bottom up forecast on data that is still being collated. This situation supports the continuing use of base year costs for transmission lines. ElectraNet also used a revealed costs approach to develop some categories of its proposed forecast: asset management, network operations, maintenance support and corporate support."

104 AER, Draft Decision 2007, page 155. The AER upheld this position in its Final Decision, approving ElectraNet's opex forecasting methodology, including the use of zero based forecasts to reflect changing asset management practices and implementation of the new maintenance regime.

105 AER, Draft Decision, page 38.

106 AER, Draft Decision, page 149 (footnotes from original omitted).

The AER's contentions that ElectraNet is operating in a steady state environment are at odds with its earlier acceptance in the AER's determination for the 2008-2013 regulatory control period that ElectraNet was in the process of introducing a new asset management and maintenance regime. [107] As the AER stated in its draft determination for the 2008-2013 regulatory control period, the AER's consultant, SKM, had noted that actual operating expenditure in the relevant base year was insufficient to provide a sustainable and efficient operation: [108]

> "The AER considers that the adoption and implementation of the new asset management and maintenance regime is a prudent action by ElectraNet, which should result in a better understanding of its network and better maintenance practices. It also notes that SKM has indicated its support for the new maintenance regime, and has stressed that it considered the maintenance practices of the early part of the current regulatory period to be unsustainable."

The AER's Draft Decision for the forthcoming regulatory control period also suggested that ElectraNet's forecast increase in corrective maintenance expenditure compared to the base year lacked supporting evidence. For example, the AER claimed that it had not observed any significant capex or opex overspends that may indicate a need for increased future corrective maintenance expenditure, noting that:[109]

> "A large overspend may indicate that the occurrence of high impact risk events that required urgent and unscheduled correction."

In contrast to the AER's assertion, however, there are examples of large overspends incurred on urgent and unscheduled correction:

- Expenditure on lines corrective maintenance in 2011-12 totalled $6.1 million (against an allowance of $1.1 million) an increase of almost 300 per cent on the prior year, as a direct response to new information regarding transmission line fire start risk. This risk also required the reprioritisation of available resources from operational refurbishment activities.
- Expenditure on lines corrective maintenance totals $14.7 million to address revealed risk against a total allowance of $5.3 million, an increase of 275 per cent.

These examples illustrate instances where ElectraNet has overspent its corrective maintenance allowance to address emerging critical risk issues. The examples contradict the AER's assertion that there are no such examples, and its conclusion that ElectraNet's corrective maintenance forecast does not comply with the Rules.

<u>Conclusion</u>

ElectraNet does not accept that the use of a top down revealed cost extrapolated forecasting approach provides a reasonable expectation of its realistic operating expenditure requirements for all cost categories in the forthcoming regulatory period.

In developing its revised proposed opex forecast, ElectraNet has applied a combination of:

- a base-year-extrapolation to those cost categories for which the efficient-base-year is representative of future costs; and
- a zero-base forecast methodology to those components for which the base-year does not provide an efficient base level that is reflective of known expenditure requirements.

107 AER, Draft Decision 2007, page 161.
108 AER, Draft Decision 2007, page 155.
109 AER, Draft Decision, Fn 475, page 158.

As already noted, this approach is consistent with the AER's earlier approach to forecasting operating expenditure and, most importantly, better reflects the requirements of the Rules and the National Electricity Law.

Zero-based forecast components comprise:

- routine maintenance;
- corrective maintenance;
- operational refurbishment;
- network optimisation;
- insurance; and
- land tax.

These forecasts are presented in the relevant sections below.

7.3 Base year

AER Draft Decision

In its Draft Decision, the AER did not approve the use of 2011-12 (year 4) as representative of efficient or recurrent costs. The AER instead applied 2010-11 (year 3) as the base year, which it considered to be an efficient recurrent base year, for the purposes of deriving the opex forecast.[110]

The AER noted that 2011-12 represented a distinctive 'step up' in comparison with the previous three years of the current period and concluded that using year 4 as the base year will place an upward bias on the forecast for the next regulatory control period.[111]

ElectraNet's Response

ElectraNet does not agree that its historic costs incurred in 2011-12 are not efficient or representative. Overall these revealed costs are more reflective of prevailing expenditure drivers and revealed risks than 2010-11 and therefore ElectraNet's forecast opex requirements.

Nevertheless, ElectraNet has incorporated the base year (2010-11) substituted by the AER for the purposes of developing its opex forecast for the relevant controllable operating expenditure allowances, with appropriate step changes to account for ElectraNet's changing business environment.

[110] AER, Draft Decision, page 149.
[111] AER, Draft Decision, page 150.

7.4 Opex efficiency factor

AER Draft Decision

The AER was not satisfied that ElectraNet's forecast operating expenditure reasonably reflects the efficient costs required to achieve the operating expenditure objectives for the next regulatory control period. On this basis, the AER applied an operating expenditure efficiency factor adjustment to the 2010-11 base year total controllable opex of 2.5 per cent, concluding that:[112]

- ElectraNet has introduced a formalised improvement and innovation programme under which it identified inefficiencies in its current practices and implemented solutions to reduce such inefficiencies;
- financial incentives linked to specified performance targets exist within ElectraNet's outsourced maintenance contract with SA Power Networks;
- the AER does not agree with ElectraNet that allowing for the removal of inefficiencies in the regulatory forecasts will weaken the incentive properties of the EBSS; and
- for the 2008-2013 regulatory control period, ElectraNet achieved operating expenditure efficiencies of 2.9 per cent relative to the AER determination in the first three years of the regulatory control period.

The AER then trended forward this reduced base year amount to establish the AER's substitute forecast for the next regulatory period (with the addition of limited step changes and other adjustments).

ElectraNet's Response

ElectraNet is deeply concerned that the AER's proposal to apply an opex efficiency factor to forecast controllable opex would lead to ElectraNet not being provided with a reasonable opportunity to recover its efficient costs (as required by the pricing principles in the NEL).

Further, ElectraNet submits that such a proposal is fundamentally inconsistent with how the incentive regulation framework is intended to work and the intention that an efficiency benefit sharing scheme provide for a fair sharing of efficiency gains and losses.

The following sections address the matters raised by the AER and describe:

- the intended operation of the AER's incentive framework for operating expenditure, which is required to be consistent with various matters set out in the Rules; and
- the specific deficiencies of this decision in its application to the forecast operating expenditures of ElectraNet.

The material set out in the following sections demonstrates that the proposed efficiency factor for operating expenditure is clearly inconsistent with the intent of the Rules and the framework as implemented by the AER in the Efficiency Benefit Sharing Scheme (EBSS) and that the application of the proposed efficiency factor to ElectraNet's operating expenditure forecast is not valid.

The material related to the operation of the incentive framework and the EBSS is supported by expert advice from Jeff Balchin of PricewaterhouseCoopers (included as Appendix K).

[112] AER, Draft Decision, page 154-155.

Inconsistency with incentive framework

The application of a revenue cap to a TNSP together with the EBSS is intended to provide a reward (penalty) to the TNSP from a marginal improvement (decline) in the level of operating expenditure. In addition, the reward (penalty) from such improvements is intended to be independent of the year in which improvement (decline) occurs, thus providing a continuous and constant incentive for cost reductions.

The outcome that is intended from these incentives is that the TNSP achieves and reveals efficient operating expenditure. In this context, efficiency means:

- minimising the level of operating expenditure required to meet a given outcome and searching for improvements to this end;
- seeking an efficient balance between operating and capital expenditure; and
- balancing the level of operating expenditure against the service outcomes for consumers (as reflected in reliability standards and the service target performance incentive scheme).

The mechanism that is used to provide the incentive for cost reduction for operating expenditure is to permit the TNSP to retain the benefit from spending less than the regulatory allowance, and for this benefit to be retained for a period of 5 years after the year in which the improvement occurred.

The retention period needs to be constant across the regulatory period – without this constancy, the incentive for improvement would be diluted across the period. Figure 7-2 shows a stylised example of how these measures are intended to work.

Figure 7-2: EBSS example with $5 million saving in year 1

				Current regulatory period					*Next regulatory period*		
[1]	**Opex forecast**	100	100	100	100	100	95	95	95	95	95
[2]	**Actual opex**	95	95	95	95	95	95	95	95	95	95
[3]	***Underspend***	*5*	*5*	*5*	*5*	*5*					
[4]	***Incremental gain***	*5*	*0*	*0*	*0*	*0*					
[5]	***EBSS yr 1***	*5*	*5*	*5*	*5*	*5*	*5*				
[6]	***EBSS yr 2***		*0*	*0*	*0*	*0*	*0*	*0*			
[7]	***EBSS yr 3***			*0*	*0*	*0*	*0*	*0*	*0*		
[8]	***EBSS yr 4***				*0*	*0*	*0*	*0*	*0*	*0*	
[9]	***EBSS yr 5***					*0*	*0*	*0*	*0*	*0*	*0*
[10]	**Within-period gain**	5	5	5	5	5	0	0	0	0	0
[11]	**EBSS amount**						5	0	0	0	0
[12]	**Total gain**	**5**	**5**	**5**	**5**	**5**	**5**	**0**	**0**	**0**	**0**

In this example:

- a sustained reduction in expenditure is made in year 1 of $5 million;
- the TNSP retains the benefit of that gain during the regulatory period (row 10);
- the EBSS delivers another year of gain in the next period (row 11), thus delivering the intended retention period; and
- the new operating expenditure allowance for the next regulatory period takes account of this new “revealed” efficient level of expenditure.

Figure 7-3 shows the operation of the scheme where the sustained gain is made in the third year of the regulatory period. The pay-off to the TNSP from making the gain is the same as before, the only difference being that a greater proportion of the reward is provided through the EBSS.

Figure 7-3: : EBSS example with $5 million saving in year 3

		Current regulatory period					*Next regulatory period*				
[1]	**Opex forecast**	100	100	100	100	100	95	95	95	95	95
[2]	**Actual opex**	100	100	95	95	95	95	95	95	95	95
[3]	***Underspend***	*0*	*0*	*5*	*5*	*5*					
[4]	***Incremental gain***	*0*	*0*	*5*	*0*	*0*					
[5]	***EBSS yr 1***	*0*	*0*	*0*	*0*	*0*	*0*				
[6]	***EBSS yr 2***		*0*	*0*	*0*	*0*	*0*	*0*			
[7]	***EBSS yr 3***			*5*	*5*	*5*	*5*	*5*	*5*		
[8]	***EBSS yr 4***				*0*	*0*	*0*	*0*	*0*	*0*	
[9]	***EBSS yr 5***					*0*	*0*	*0*	*0*	*0*	*0*
[10]	**Within-period gain**	0	0	5	5	5	0	0	0	0	0
[11]	**EBSS amount**						5	5	5	0	0
[12]	**Total gain**	**0**	**0**	**5**	**5**	**5**	**5**	**5**	**5**	**0**	**0**

Applying the above framework requires care to ensure that the intended incentive properties are retained, while simultaneously ensuring that TNSPs are provided with “a reasonable opportunity to recover at least efficient cost” as specified in the revenue and pricing principles in the National Electricity Law. Two specific issues are relevant in this context.

First, the rewards and penalties under the incentive scheme are computed by comparing the actual expenditure to the regulatory allowance for expenditure. Thus, in order for a TNSP to have “a reasonable opportunity to recover at least efficient cost”, the regulatory allowance for expenditure must take account of the actual characteristics of a TNSP’s expenditure and the drivers of cost. If the evidence indicates the volumes of certain types of activities are not smooth but are predictably “lumpy”, then it is essential for the forecast of expenditure to reflect that anticipated profile of expenditure. The incentive scheme described above will provide an incentive for a TNSP to minimise its expenditure in each year, but it cannot turn a “lumpy” stream of expenditure requirements into a smooth pattern.

This matter is most relevant to ElectraNet’s corrective maintenance and operational refurbishment, which has already been discussed.

Secondly, the objective of the above incentive scheme is to encourage the company to reveal its efficient level of expenditure, with this information then used to set the starting point for the new regulatory allowance.

The incentive scheme is not intended to reveal the efficient “trend” rate of change in operating expenditure, which appears to be EMCa’s contention. To the contrary, if the improvement that a TNSP has made in one period is used to inform the regulatory allowance for the next period (i.e. by assuming efficiencies can be replicated beyond those already included in the outturn (revealed efficient) costs) then the incentive to minimise expenditure will be substantially reduced.

This is illustrated in Figure 7-4 and Figure 7-5, which replicate Figure 7-2 and Figure 7-3, but with the additional assumption that the regulator observes the one-off gain made in the current regulatory period and assumes that this gain is able to be replicated from the start of the next period.

Figure 7-4: EBSS example with $5 million saving in year 1 but assuming gain can be replicated from the start of the next period

		Current regulatory period					Next regulatory period				
[1]	**Opex forecast**	100	100	100	100	100	90	90	90	90	90
[2]	**Actual opex**	95	95	95	95	95	95	95	95	95	95
[3]	***Underspend***	*5*	*5*	*5*	*5*	*5*					
[4]	***Incremental gain***	*5*	*0*	*0*	*0*	*0*					
[5]	***EBSS yr 1***	*5*	*5*	*5*	*5*	*5*	*5*				
[6]	***EBSS yr 2***		*0*	*0*	*0*	*0*	*0*	*0*			
[7]	***EBSS yr 3***			*0*	*0*	*0*	*0*	*0*	*0*		
[8]	***EBSS yr 4***				*0*	*0*	*0*	*0*	*0*	*0*	
[9]	***EBSS yr 5***					*0*	*0*	*0*	*0*	*0*	*0*
[10]	**Within-period gain**	5	5	5	5	5	-5	-5	-5	-5	-5
[11]	**EBSS amount**						5	0	0	0	0
[12]	**Total gain**	**5**	**5**	**5**	**5**	**5**	**0**	**-5**	**-5**	**-5**	**-5**

Figure 7-5: EBSS example with $5 million saving in year 3 but assuming gain can be replicated from the start of the next period

		Current regulatory period					Next regulatory period				
[1]	**Opex forecast**	100	100	100	100	100	90	90	90	90	90
[2]	**Actual opex**	100	100	95	95	95	95	95	95	95	95
[3]	***Underspend***	*0*	*0*	*5*	*5*	*5*					
[4]	***Incremental gain***	*0*	*0*	*5*	*0*	*0*					
[5]	***EBSS yr 1***	*0*	*0*	*0*	*0*	*0*	*0*				
[6]	***EBSS yr 2***		*0*	*0*	*0*	*0*	*0*	*0*			
[7]	***EBSS yr 3***			*5*	*5*	*5*	*5*	*5*	*5*		
[8]	***EBSS yr 4***				*0*	*0*	*0*	*0*	*0*	*0*	
[9]	***EBSS yr 5***					*0*	*0*	*0*	*0*	*0*	*0*
[10]	**Within-period gain**	0	0	5	5	5	-5	-5	-5	-5	-5
[11]	**EBSS amount**						5	5	5	0	0
[12]	**Total gain**	**0**	**0**	**5**	**5**	**5**	**0**	**0**	**0**	**-5**	**-5**

What these figures demonstrate is that if a TNSP expects its revealed efficiency gains to be factored into both the setting of the starting point for the new regulatory allowance (the base year) and into the assumed change in expenditure from that point onwards, then the reward (penalty) from an improvement (decline) in operating expenditure is substantially diminished. If the assumed efficiency continues, there is no benefit derived by the firm (and a penalty is incurred it if is not).

In fact, if the above examples are extended to include a third regulatory period they would show that the TNSP would be required to 'pay back' all of the efficiency gains. In effect, the incentive properties ordinarily provided by the regulatory framework would be almost entirely eliminated, as the only benefit to the TNSP would be the timing difference between receiving the rewards and repaying them.

Furthermore, it is an approach that penalises more efficient TNSPs for delivering cost reductions (as the forecast allowance is subject to a double reduction), while treating other TNSPs more favourably. It is therefore an approach that is substantially at odds with the recent Rule changes, which are intended to sharpen the incentives for cost reduction.

Factual errors in application

As discussed above, the AER Draft Decision applies a 2.5 per cent efficiency factor to ElectraNet's base year expenditure. In addition to the inconsistencies of this approach with the incentive properties of the regime, the proposed adjustment is based on a fundamental misunderstanding of ElectraNet's actual cost position.

Firstly, there is no specific basis or evidence to support the AER's proposed 2.5 per cent efficiency factor, noting that this applies in full from the outset. All existing efficiencies have been factored into the expenditure forecasts proposed by ElectraNet. For example, efficiencies from competitive maintenance procurement processes are specifically built into the routine maintenance program approved by the AER:

- ElectraNet competitively outsources all field maintenance activities under term contracts.
- The primary maintenance contract in place at the start of the current regulatory control period included financial incentive arrangements in the form of specified productivity savings built into the contract. This contract ceased in September 2011. A range of separate contracts for specialised maintenance activities ceased progressively between 2009 and 2012.
- ElectraNet undertook a competitive process to re-engage contractors for the delivery of its maintenance program. On the basis of its review of these arrangements, and an independent assessment undertaken for ElectraNet by Evans & Peck, EMCa concluded that ElectraNet's procurement of maintenance services provides it with effective resources on reasonable commercial terms at competitive costs, under arrangements that allow services to be efficiently provided with appropriate governance and control.[113]
- Based on the outcomes of this competitive process, a series of new maintenance contracts were established which took effect progressively from late 2009 to October 2011. The competitive unit rates and pricing arrangements of these contracts are reflected in the bottom-up routine maintenance forecast contained in ElectraNet's Revenue Proposal, as approved by the AER. Reflecting prevailing market rates, the unit costs in this contract increased from those under the previous contract.
- The new primary maintenance contract contains a commitment to work to identify productivity improvements, with any resulting gains to be shared by the parties. However, neither this contract nor any other maintenance contract now in place contains specified productivity savings or financial incentive payments.

The claimed 2.5 per cent efficiency improvements are entirely speculative and unsubstantiated. ElectraNet also notes that neither EMCa nor the AER has provided any evidence or basis for the application of these purported savings across its entire controllable opex base.

Secondly, there is no logical nexus between the quantum of efficiencies that ElectraNet has been able to find in the current regulatory period and any efficiencies that ElectraNet may or may not achieve in the forthcoming regulatory period.

EMCa's recommendation for a 2.5 per cent efficiency allowance appears to have been influenced by the observation that 'ElectraNet achieved operating efficiencies of 2.9 per cent relative to the AER determination for the current regulatory control period, in the three years of "actual expenditure."'[114] This is evidence of ElectraNet's historic achievements within the *current* regulatory control period and, other than inclusion of revealed efficiencies achieved in or prior to the base year as noted above, bears no relevance to ElectraNet's forecasts.

113 EMCa Report, page 139.
114 EMCa Report, page 140.

In addition, the AER's discussion on future efficiency gains appears to have drawn on the initiatives that ElectraNet is assumed to have undertaken *after* the base year. As demonstrated above, it is inconsistent with the opex incentive scheme for a TNSP's achievements in one regulatory period to set a target for efficiency gains in the next period – this will reduce the incentive to make efficiency gains and lead to the expropriation of the benefits that were reasonably expected from past initiatives.

ElectraNet will obviously pursue efficiencies in the forthcoming regulatory control period (provided it has an appropriate incentive to do so), but whether or not it will be able to find more, or less, or the same amount, or indeed suffers some efficiency loss as a consequence of spending more than the opex allowance, is a matter that can only be assessed at the end of the regulatory period. Importantly, any gains actually realised will be shared with customers under the EBSS.

The effect of ElectraNet's initiatives in or prior to the base year are already reflected in the base year (such as competitive maintenance prices, as described above) and the effect of ElectraNet's initiatives after the base year will be reflected in the base year that is used to establish the regulatory allowance for the subsequent regulatory control period. It is clearly incorrect to use ElectraNet's past initiatives to support a finding that ElectraNet will be able to identify and implement other initiatives that will achieve a similar magnitude of efficiency gains relative to the opex allowance in future. In fact, a business that has found past efficiencies would be expected to find it more difficult to find future efficiencies.

Thirdly, ElectraNet also rejects EMCa's reasons for focussing on only the first three years of the regulatory period. EMCa attempted to explain away the forecast higher costs in years 4 and 5 of the current regulatory control period by its claim that:

> "…we were also informed that work had been "brought forward" into the RCP [regulatory control period] with an implied view that it would be commercially prudent for ElectraNet to spend up to the "allowance" contained within the AER's previous decision".[115]

In the first instance, ElectraNet rejects EMCa's notion that work has been "brought forward" to spend up to the opex allowance in the current period. The volume of known corrective maintenance work in particular that ElectraNet has detailed in its Revenue Proposal demonstrates the higher than base year expenditure requirements ElectraNet now faces. ElectraNet also notes that this incurred overspend is inconsistent with the claims made by EMCa that additional efficiencies have been revealed in the later years of the current period. In the second instance, the financial incentives of the EBSS would penalise ElectraNet for taking such an approach, which would therefore only occur if absolutely necessary based on underlying drivers to meet service delivery obligations. ElectraNet's actual revealed historic cost profile reflects its efficient costs.

Finally, the AER's discussion of the trend in operating expenditure also seems to ignore the fact that its operating expenditure forecast already assumes material productivity improvements over the next regulatory period. In particular, the AER has applied "scale factors" to incorporate an assumption that an efficient entity will be able to restrict the rate of growth in operating activities below the growth of its asset base. The AER's application of an efficiency factor is not only inconsistent with the incentive framework, but it would also double count known efficiencies that have already been factored into the expenditure forecasts.

115 EMCa Report, footnote 100, page 140.

Summary

ElectraNet strongly challenges the suggestion that its operating expenditure should be adjusted by a 2.5 per cent per annum efficiency factor. The application of such an efficiency factor – which appears to be partly based on a misunderstanding of the EBSS, and partly based on an inaccurate understanding of ElectraNet's current cost position – would severely damage the incentive properties of the regulatory regime.

The AER is incorrect to say that it is removing only existing identified inefficiencies. The AER does not identify any specific inefficiencies that are being removed. In effect, the primary basis for the AER's efficiency factor is the claim that as ElectraNet has achieved efficiencies in the current period it is reasonable to expect further efficiencies in the forthcoming regulatory period.[116]

The AER's proposed approach to apply an opex efficiency factor in the circumstances set out above is fundamentally inconsistent with the incentive properties of the regulatory regime. The regime is intended to operate such that a TNSP is to be rewarded for efficiency gains, not penalised for previous achievements. If ElectraNet does find future efficiencies amounting to 2.5 per cent through its additional efforts, under the AER Draft Decision ElectraNet would not be awarded for this. It is difficult to see how such a position reconciles with the Rules, in particular, that an efficiency benefit sharing scheme should provide for the "fair sharing" of efficiency gains. Under the AER's proposal there is no "sharing" of efficiency gains.

The opex forecast does not (and is not required to) incorporate future unknown and speculative efficiency improvements. In these circumstances it is not open to the AER to apply an efficiency adjustment to ElectraNet's forecast opex.

Accordingly, ElectraNet has not applied an opex efficiency factor to the operating expenditure forecasts in this revised Revenue Proposal.

7.5 Step changes - Controllable

7.5.1 Routine maintenance

AER Draft Decision

The AER approved ElectraNet's proposed routine maintenance forecast of $80.9 million ($2012-13) for the next regulatory control period, noting that ElectraNet had presented evidence of having thoroughly considered its routine maintenance requirements.[117]

ElectraNet's Response

ElectraNet has reviewed its Routine Maintenance program in light of the adoption of the 10 per cent probability of exceedance demand forecasts, which have resulted in the deferral of substantial investment from its capital program.

This deferral has decreased the capital augmentation program, thereby reducing the number of new assets requiring maintenance, but also delayed a number of large substation replacement projects with an augmentation component, resulting in increased maintenance requirements to extend the life of these assets.

116 AER, Draft Decision, page 154-155.
117 AER, Draft Decision, page 156.

While the net impact of these deferrals is an overall increase in routine maintenance requirements, this impact is not considered material. ElectraNet has therefore maintained in its revised Revenue Proposal the routine maintenance forecast as approved by the AER in its Draft Decision.

7.5.2 Corrective maintenance

AER Draft Decision

ElectraNet proposed $68.8 million for corrective maintenance. ElectraNet presented costs in two forms: a backlog of already identified defects and a base level of defects.[118]

The AER did not approve ElectraNet's proposed corrective maintenance forecast, and used historic costs from 2010-11 for corrective maintenance to develop a substitute forecast of $43.7 million. The AER gave the following reasoning for this decision:

> 'ElectraNet overstated its corrective maintenance forecast because it did not properly allow for reductions in the rate of new defects that will arise once the first round of the condition assessment cycle is complete'.[119]
>
> 'ElectraNet also overstated the backlog of defects in its opex forecast. It estimated the substation defects not allocated to refurbishment or replacement work programs form a backlog of about 10 months. EMCa estimated the backlog to be around four to five months. EMCa's estimate was lower than ElectraNet's even though EMCa assumed a lower incoming rate of defects.'[120]
>
> 'EMCa did not find evidence that ElectraNet assessed life cycle 'correct now' versus 'correct later' engineering and/or economic options for corrective maintenance.'[121]

ElectraNet's Response

ElectraNet does not agree with the AER's assessment of ElectraNet's forecast corrective maintenance and does not accept that the substituted forecast proposed by the AER will provide an adequate allowance to enable ElectraNet to meet the opex objectives in the Rules and recover its efficient corrective maintenance costs. ElectraNet addresses each of the above issues in turn.

Defect rates

ElectraNet has projected forward corrective defect rates based on recent historical levels of actual revealed risk. ElectraNet's Asset Management Strategy[122] explains the long-term asset management and maintenance strategy which is being progressively implemented over time. A key point to understand here is the relative maturity of the integrated maintenance program for different asset classes. This is recognised by both the AER and EMCa.

118 AER, Draft Decision, page 157.
119 AER, Draft Decision, page 157.
120 AER, Draft Decision, page 157.
121 AER, Draft Decision, page 158.
122 Board approved Asset Management Strategy, May 2012 (submitted with Revenue Proposal).

For substations, ElectraNet would expect to see a reduction in the rate of new defects by the end of 2013-2018 regulatory control period as a result of the advanced level of maturity of the substation asset condition dataset (essentially 100 per cent complete) and the replacement and targeted operational refurbishment programs carried out in the 2008-2013 regulatory period – if it were not for the offsetting increased expenditure requirement on new assets at start of life which is currently being experienced (discussed further below).

For transmission lines, a similar reduction in the rate of new defects is not expected until beyond the 2013-2018 regulatory period for the following reasons:

- The less advanced maturity of the integrated asset management program;
- Long inspection cycles mean completion of the first cycle of transmission line condition assessment will not occur until the end of the 2013-2018 regulatory period (the asset condition dataset is currently only about 40 per cent complete);
- Unlike substations, no major transmission line replacement works have been undertaken in the current regulatory period and none are planned for the next (only targeted line refit work and some refurbishment is planned to address already identified high risk line component issues with shorter life cycles); and
- The larger population of transmission line assets entering the later stages of the asset lifecycle (about 42 per cent of transmission lines will exceed their nominal life of 55 years by the end of the 2013-2018 regulatory period).

Consequently, it is highly improbable that the incoming rate of new defects for transmission lines will decline in the 2013-2018 period.

In relation to the offsetting costs for substations, the Draft Decision states:[123]

> "ElectraNet submitted that the decreasing trend of rate of incoming defects rates, was offset by the 'bath tub effect', which is an increased expenditure requirement at the start and end of asset life. But the AER disagrees that the bath tub effect off sets ElectraNet's decreased corrective maintenance requirements. Modern substation equipment generally minimises this effect because it is modular, prefabricated and pretested and therefore reduces 'start of life' defects. Also, warranty provisions may provide for the supplier or contractor to bear the costs of any 'start of life' defects."

The claim that modern substation equipment reduces "start of life" defects is without foundation and is inconsistent with ElectraNet's operational experience.

Industry experience suggests that infant mortality is a dominant failure mode for "complex systems" such as electrical utility assets.[124] Substation secondary systems are becoming increasingly more complex to achieve higher levels of automation and control functionality. Increased functionality and secondary system complexity adds to the risk of infantile failure. In addition, secondary system designs are increasingly reaching market with little or no field experience or history. Design issues are often discovered early in the product life in the field, resulting in outages, repair and rework. This type of failure increases the cost of substation maintenance during the early life of the substation.

With regard to warranty provisions, these only cover the cost of a failed asset within the warranty period, and exclude consequential damage or associated costs even within this period. ElectraNet has sound warranty provisions in place for primary plant assets (and

123 AER, Draft Decision, page 157.
124 See for example "Strategy for Condition Based Maintenance and Updating of Substations", CIGRE 1996:23-105.

extended warranties on individual high capital value items such as transformers and HV underground cables) and defect liability to cover faulty or poor quality workmanship.

However, the majority of defects recorded in substation early life are not primary plant related. They are generally related to secondary (protection and control) systems and minor plant, consistent with industry wide experience of higher infant mortality rates in “complex systems”. Only limited warranties are generally available for these assets, and as such early life failures show up as corrective maintenance requirements.

In a recent example in Vietnam, a 500kV transmission transformer failed due to a relatively simple but catastrophic failure of a bushing.[125] The bushing failure was most likely the result of an inherent design or manufacturing defect or possibly an issue with installation. The failure resulted in the need to remove the transformer from service, repair the damage, place a spare transformer temporarily in place until the main transformer could be returned, some 12 months later. The bushing manufacturer repaired the bushing under its warranty provisions, but the cost of the repairs and restoration were borne by the utility concerned. It is extremely unlikely that any bushing manufacturer would cover the cost of the consequential damage, the repair and restoration works or the loss of production. The cost of the bushing was estimated at $50,000, significantly lower than the total cost of the event to the utility, estimated to be in the “millions”. Incidents of this type are not uncommon and in aggregate add to the cost of maintenance for utilities, particularly during the early stages of the design life of an asset type.

In addition, it is noted that the deferral of a number of major substation replacement projects (with a load driven component) through the adoption of 10 per cent probability of exceedance demand forecasts will result in further pressure on substation corrective maintenance requirements.

ElectraNet considers that the claim that it has over estimated incoming defect rates is not supported by the available evidence. ElectraNet also notes the decision of the Australian Competition Tribunal that dealt with the regulatory allowance to be provided in respect of defect maintenance for TransGrid. The Tribunal noted that the AER had raised the issue of newer technology decreasing defect rates, however no evidence had been provided by the AER on this issue in order that it could be resolved[126]. The Tribunal noted that in any case, over the relatively short span between the base period and the current period the effect seems likely to be small.[127]

<u>Backlog of defects</u>

The AER claims that ElectraNet has overstated the backlog of substation defects in its opex forecast:[128]

> “ElectraNet also overstated the backlog of defects in its opex forecast. It estimated the substation defects not allocated to refurbishment or replacement work programs form a backlog of about 10 months. EMCa estimated the backlog to be around four to five months.”

The claim that ElectraNet overstated the backlog of substation defects is incorrect.

EMCa has made a data error in its assessment by overstating the volume of incoming defects that can be addressed by the end of the current regulatory period on both lines and

125 Sinclair Knight Merz recent project experience.
126 Application by EnergyAustralia & Others (2009) ACompT 8.(313)
127 Application by EnergyAustralia & Others (2009) ACompT 8.(313)
128 AER, Draft Decision, page 157.

substations. As a result EMCa has underestimated the backlog that will exist at that time in assessing the corrective maintenance forecasts. This is explained in the following sections.

Substations

For substations, EMCa concluded that:[129]

> "The backlog at 1 April 2012 stood at 1,800 defects. The incoming rate of defects is averaging 400 per month. The backlog therefore represents 4.5 months of incoming defects. Assuming an annual incoming rate of $3.5 million, the value of the defect backlog is approximately $1.5million."

These calculations are incorrect. The correct incoming defect rate based on the data supplied to EMCa was approximately 175 per month.[130] The backlog therefore represents approximately 10 months of incoming defects. Adopting the same incoming rate assumed by EMCa of $3.5 million, the value of the backlog is therefore estimated at $2.9 million.

ElectraNet notes that the estimated value of the backlog incorporated in its original forecast was $2.5 million, significantly less than the corrected value above.

Transmission lines

For transmission lines, EMCa concluded that:[131]

> "The backlog at 1 April 2012 stood at 5,000 defects. The incoming rate of defects is averaging 500 per month. The backlog therefore represents 10 months of incoming defects. Assuming an annual incoming rate of $4.9 million, the value of the defect backlog is approximately $4.2 million."

These calculations are incorrect. The correct incoming defect rate based on the data supplied to EMCa was approximately 235 per month.[132] The backlog therefore represents approximately 21 months of incoming defects. Adopting the same incoming rate assumed by EMCa of $4.9 million, the value of the backlog is therefore estimated at $8.6 million.

ElectraNet has therefore maintained its original estimated values for the maintenance backlog in its lines and substation corrective maintenance forecasts.

<u>'Correct now' versus 'correct later'</u>

In relation to corrective maintenance tasks, the Draft Decision states:[133]

> "EMCa did not find evidence that ElectraNet assessed life cycle 'correct now' versus 'correct later' engineering and/or economic options for corrective maintenance. In deciding whether ElectraNet's proposal meets the opex criteria, the AER must have regard to the opex factors, which include the extent of substitution possibilities between opex and capex. It considered a prudent operator in ElectraNet's circumstances could reasonably have undertaken an economic and/or engineering assessment, which would have resulted in some deferrals of corrective maintenance opex or replacement capex."

129 EMCa report, page 125, footnote 84.

130 It has come to the attention of ElectraNet that while the data supplied in its response ENET182 was correct, the summary charts which appear in this document are incorrectly labelled, potentially leading to confusion over the rate of incoming defects.

131 EMCa report, page 127, footnote 87.

132 It has come to the attention of ElectraNet that while the data supplied in its response ENET182 was correct, the summary charts which appear in this document are incorrectly labelled, potentially leading to confusion over the rate of incoming defects.

133 AER, Draft Decision, page 158.

The AER also concluded that:[134]

> "a significant number of defects that drive corrective maintenance are "asset related" and do not have safety / environment or reliability / availability impacts. Decisions relating to corrective maintenance of "asset risks" necessarily involve engineering economic trade-offs. ElectraNet suggested that only defects with safety / environment or reliability / availability are considered for corrective maintenance. EMCa found that this category of defect "notis" were about 45 per cent of all "notis" and the rest were "asset risks" which present a risk of asset component failing but without the safety / environment or reliability / availability impacts"'.

Contrary to EMCa's comments, ElectraNet's framework for assessing and prioritising defects for corrective action, System Condition and Asset Risk (SCAR), incorporates a fully documented engineering risk based assessment for all known asset failure modes and consequences (as discussed earlier in Chapter 5).

Only asset failure modes that are unacceptable – those related to safety, environment, operational (network) or transmission line fire start risk – are used to model corrective maintenance effort. This means the corrective maintenance profiles identified are:

- Based only on unacceptable failure modes for both transmission line and substation assets (and therefore require a relatively short response time – generally less than 12 months).[135]
- In the case of substations, the defect list represents assets that have already commenced failure (or in some cases have already failed and as a result will continue to degrade network performance until restored to service); and
- In the case of transmission lines, the defect list represents assets that have either failed or commenced failure and have unacceptable failure consequences, which are entirely related to safety or fire start risk (note that these include so called asset risk related defects).

The claim that asset risk related defects are not identified for corrective maintenance is incorrect. The asset related line defects assessed for corrective response (generally within 120-540 days) are characterised by assets which have commenced failure and pose unacceptable public safety and fire start risks. The risk and consequence of asset failure for these defects is such that it is not possible to prudently delay rectification beyond short term response.

All defects that do not have unacceptable failure consequences have already been identified for near term response through the operational refurbishment program or other scheduled works, or identified for ongoing monitoring and review.

The case study in Box 7-1 provides a practical illustration of the types of asset related risks mitigated through corrective line maintenance, which are included in ElectraNet's corrective maintenance forecast.

A key point of this example is to illustrate the consequences of failing to detect and correct asset deterioration related to high risk failure modes prior to full functional failure of the asset, including higher corrective maintenance costs and in this case interruption to customer supply.

134 AER, Draft Decision, page 107.

135 ElectraNet notes that some line failure modes have longer response times (<24 months) based on P-F intervals but have the same unacceptable failure consequences.

The outcomes of the Victorian Bushfire Royal Commission underline the importance of a robust transmission line asset management framework. Adequate corrective lines maintenance is a critical part of this framework:

> "International expert Professor Nicholas Hastings explained that an inspection regime's suitability for limiting asset failure should be assessed by reference to the extent to which the regime allows incipient failures to be detected before they proceed to full functional failure - that is, the asset failing while in service. The regime should take into account how the assets fail, how failures can be detected and the effect of failure."[136]

In summary, there is no credible "correct later" option for addressing the backlog of corrective maintenance asset defects identified beyond the 2013-2018 regulatory period.

<u>Conclusion</u>

As ElectraNet has demonstrated above:

- projected defect rates are informed by recent historical levels of actual revealed risk, based on an established platform of completed substation asset condition information, and a developing dataset on transmission line asset condition (presently 40 per cent complete);
- the claims that ElectraNet has overstated the backlog of corrective substation and transmission line maintenance are based on a misinterpretation of data by EMCa; and
- there is no credible or prudent "correct later" option available to ElectraNet to address asset defects identified for corrective maintenance response, which require a short-term response given the nature of the risks involved including fire start and public safety risks.

[136] *Victorian Bushfire Royal Commission report*, page 160.

Box 7-1: Transmission line defect case study

Asset risk: Insulator assembly attachment hardware (bow shackle) failure

An insulator assembly attachment (bow shackle) failure mode has been identified which is progressive deterioration of the clevis pin retainer [split-pin or split-pin with screwed nut] followed by eventual dislodgement of the clevis pin from the shackle. Full failure of the shackle results in dropping of the insulator assembly and supported high voltage conductor to ground or onto other assets. The P-F interval is estimated at 2 years.

ElectraNet incident:

In January 2010 a bow shackle failure occurred on a 132kV transmission line in the Adelaide Hills causing a phase conductor to fall to the ground (Interruption Event 2176). Investigations determined that the shackle failed due to the clevis pin retainer, a split-pin, corroding away enabling the clevis pin to work loose and slip out of place in the shackle due to the swing of the insulator assembly. This movement, caused by wind, eventually resulted in the shackle being unable to support the weight of the insulator assembly and conductor. Weather at the time of the incident was fine but with high winds.

Further, it was determined that the shackle used in this transmission line was an older design which was no longer used (newer designs incorporate a nut and split-pin retainer on the clevis pin). There was no evidence to show that there were deficiencies in material, fabrication or application of the failed shackle.

Failure consequences:

- Grassfire started from arcing when the conductor contacted the ground with 20 Hectares of grassland burnt in a high bushfire risk zone: public safety issue.
- Energised and damaged a metallic stock fence when the conductor contacted it. The stock fence ran adjacent to a residential property and local distribution supply point, damaging the supply point transformer. No persons were injured: public safety issue.
- Outage of transmission line resulting in 0.02 system minute loss: reliability impacts.
- Asset damage to transmission line insulator assembly and 200m of conductor. Damage to nearby residential local distribution supply point and stock fencing: rectification and incident investigation costs.

Summary of outcomes:

- Asset inspection activities increased in scope to enable identification and rectification of the relevant failure mode within P-F interval.
- Increased incoming rate of related asset defects due to increased asset inspection activities – increasing revealed risk.
- Emergency rectification and inspection costs of about $0.3 million.
- Validation of specific failure mode P-F interval.

ElectraNet does not accept the corrective maintenance forecast proposed by the AER is consistent with a realistic expectation of the reasonable costs required to manage its anticipated corrective maintenance requirements in the next regulatory period.

ElectraNet has therefore maintained its Revenue Proposal corrective maintenance forecasts in this revised Revenue Proposal, as set out in Table 7-2

Table 7-2 Revised corrective maintenance forecast ($m 2012-13)

	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Draft Decision	8.1	8.7	8.8	9.0	9.1	**43.7**
Revised Revenue Proposal	14.9	15.1	14.0	12.1	12.3	**68.4**

7.5.3 Operational refurbishment

AER Draft Decision

In its Draft Decision, the AER did not approve ElectraNet's operational refurbishment forecast of $64.9 million and adopted a substitute forecast of $47.0 million ($2012-13) on the basis of historic cost.[137]

The AER provided the following reasoning in support of this position:

> "The AER does not accept the proposed increase to operational refurbishment over the historical trend amount (the differential being $18.1 million). The inputs that determine ElectraNet's operational refurbishment forecast are based on historical high risk defect rates that are upwardly biased, so the operational refurbishment forecasts are overestimated."[138]

> "The AER is concerned this definition is inconsistent with ElectraNet's opex category for operational refurbishment, but rather fits its own definition of the maintenance support cost…"[139]

> "ElectraNet has not provided information about the cut-off points at which asset refurbishment projects are undertaken to justify the cost/risk (asset lifecycle economics) to understand the financial implications of these decisions."[140]

The AER also expressed concern that ElectraNet had evidently reduced its operational refurbishment expenditure in the final years of the current regulatory period, suggesting that prudent deferral of these risks is possible.

ElectraNet's Response

ElectraNet does not accept that the substituted forecast proposed by the AER will provide an adequate allowance to enable ElectraNet to meet the opex objectives under the Rules and recover its efficient operational refurbishment costs. ElectraNet addresses each of the above issues in turn.

<u>Operational refurbishment drivers</u>

The AER's reasoning in the Draft Decision appears to be based on a misunderstanding of the nature of the operational refurbishment expenditure forecast. The operational projects that make up this forecast are not based on projected defect rates but on:

- fixing known asset defects, and addressing high risk safety, environment and reliability issues through refurbishment, asset removal and hazard mitigation works, where there are unacceptable failure consequences of not undertaking the work; and

137 AER, Draft Decision, page 158.
138 AER, Draft Decision, page 285.
139 AER, Draft Decision, page 159.
140 AER, Draft Decision, page 107.

- inspection and testing activities required to enable the first complete assessment of transmission line asset condition.

Projected defect rates are more relevant to the determination of corrective maintenance requirements, as discussed above.

Definition of cost category

The AER commented on its concern in relation to the classification of asset condition assessment expenditure in its Draft Decision as follows:[141]

> "The AER is concerned this definition is inconsistent with ElectraNet's opex category for operational refurbishment, but rather fits its own definition of the maintenance support cost category (which includes: 'asset condition monitoring and analysis'). The AER is not clear why ElectraNet included this $15 million of condition assessment expenditure as asset refurbishment and therefore does not accept this forecast meets the opex objectives, because the additional expenditure may be duplicated elsewhere in the proposal."

ElectraNet's Revenue Proposal (May 2012) clearly explains that the operational refurbishment category includes activities to "provide asset information".[142] All (outsourced) field costs for these activities have consistently been categorised as operational refurbishment. ElectraNet's maintenance support cost category does include "asset condition monitoring and analysis" as noted by the AER in its Draft Decision. However, this cost category only relates to non-field internal costs as made clear in the Revenue Proposal. There is no duplication of this expenditure in the Revenue Proposal.

Ability to defer

The Draft Decision also states:[143]

> "ElectraNet chose to reduce its opex refurbishment expenditure in the final two years of the 2008–13 regulatory control period and estimated this expenditure to be less than the annual regulatory allowance for 2011–12 and 2012–13. This outcome suggests ElectraNet can prudently defer some of the cost–risk trade-offs with minimal risk impact."

ElectraNet's actual and forecast operational refurbishment expenditure forecast for 2011-12 and 2012-13 is a result of reprioritising maintenance requirements within the overall AER opex allowance, and is a direct consequence of the need to significantly overspend the corrective maintenance allowance in these years to address more immediate revealed risks.

By definition, operational refurbishment projects are packaged works of a planned nature. Short-term deferrals of such works may be possible in certain circumstances. However, ElectraNet considers that the risk of deferring rectification of the priority high risk issues identified for operational refurbishment to 2018-19 and beyond (as assumed in the Draft Decision) is unreasonable and unacceptable.

141 AER, Draft Decision, page 159.
142 ElectraNet, Revenue Proposal, page 89.
143 AER, Draft Decision, page 159.

In relation to transmission line inspection and testing, the AER Draft Decision to exclude the step changes in operational refurbishment proposed by ElectraNet would have the effect of disallowing funding for completing these activities. Not undertaking these packaged testing works designed to detect hidden failures present in ElectraNet's network – which have already resulted in incidents of asset failure and fire start in high bushfire risk areas – would lead to an unacceptable increase in risk.

The outcomes of the Victorian Bushfire Royal Commission underscore the importance of this work:

> "International expert Professor Nicholas Hastings explained that an inspection regime's suitability for limiting asset failure should be assessed by reference to the extent to which the regime allows incipient failures to be detected before they proceed to full functional failure - that is, the asset failing while in service. The regime should take into account how the assets fail, how failures can be detected and the effect of failure."[144]

> "The economic regulatory regime must include mechanisms for ensuring that safety-related matters are properly reviewed so as to minimise the risk of bushfire being caused by the failure of electrical assets."[145]

> "Additionally, the rates of failure of some important network components are climbing as those components age. Increasing failure rates warrant increased opportunities for detection."[146]

ElectraNet has responded by considering its asset failure history and asset age profile, and has continued to implement its condition monitoring programs as required where asset condition inspection is needed to adequately understand and detect unacceptable failures. The further work required on transmission line asset condition assessment is included in ElectraNet's operational refurbishment forecast.

<u>Cost / risk trade off</u>

Asset refurbishment plans are developed by considering all asset defect profiles, where possible by plant group, in order to be able to group and package work to maximise efficiency.

Projects are categorised as follows:

- High priority – where a direct impact on safety / environment or asset availability and reliability is identified.
- Medium priority – where an impact on asset availability and reliability is identified (but response may be delayed and asset condition monitored).
- Low priority – where a possible impact on asset availability and reliability is identified but further information or monitoring is required.

As discussed in Chapter 5 and earlier in this section, these projects can also be categorised as addressing:

- Condition assessment of transmission lines to better understand where these lines are in their asset lifecycle and thereby to enable future asset management decisions to minimise long-run cost (discussed earlier in this chapter).
- Safety and environmental issues, including potential fire start risk.

144 *Victorian Bushfire Royal Commission report*, page 160.
145 *Victorian Bushfire Royal Commission report*, page 168.
146 *Victorian Bushfire Royal Commission report*, page 161.

- More general asset deterioration and failure issues.

ElectraNet considers that the works for transmission line condition assessment are critical to help complete its understanding of the condition of transmission lines to facilitate delivery of transmission services at lowest long-run cost (as discussed earlier) and are therefore justified on an economic basis.

The works required to address safety and environmental issues are also necessary and prudent to be undertaken on public safety grounds based on qualitative risk assessment and analysis of potential failure consequences.

The remaining works are supported by a high level cost benefit analysis based on quantified failure consequences and impacts.

The refurbishment priorities included in ElectraNet's revised operational refurbishment forecast are summarised in Table 7-3 below.

Table 7-3 Summary of operational refurbishment projects ($m 2012-13)

Refurbishment Project Works	Risk Impacts	Timing Drivers	Cost Estimate ($m)
Condition assessment of transmission lines			*14.8*
Transmission line condition assessment projects (targeted assets)	• Unexpected transmission line asset failures: • potential fire start public safety hazard	• Public safety / fire start risk • Asset failure history (known failure mode) Multiple major incidents experienced in the recent past	14.8
Safety and environmental issues			*22.3*
Communication towers safety systems condition assessment (71 sites) and fall arrestor replacement works (11 sites)	• Non-compliance with Workplace Health and Safety / Australian Standards • Unacceptable workplace hazard for contractors and employees	• Requirement for compliance with new WH&S legislation / Australian Standards • Need for contractor and employee safety	1.0
Transmission line insulator replacements	• Transmission line asset failures: • potential fire start • public safety hazard	• Public safety / fire start risk • Asset failure history (known failure mode)	4.4
Transformer oil containment works	• Oil spillage and remediation costs • Non-compliance with environmental legislation	• Non-compliance with EPA regulations • Potential PCB contamination	3.5

Refurbishment Project Works	Risk Impacts	Timing Drivers	Cost Estimate ($m)
Network Risk Mitigation: - Aviation markers - Plant earthing - Vegetation management tools - Safety and emergency response training	• Non-compliance with Workplace Health and Safety / Australian Standards • Non-compliance with Vegetation Clearance Regulations • Lack of Emergency Restoration Structure preparation and reliability impacts • HV switching safety incident management	• Compliance with WH&S legislation • Compliance with Australian Standards (aerial hazard ID) • Public safety (fire start risk) through vegetation • Operational safety risks (aviation safety) • Safety of staff through HV switching and safety training • Emergency outage response	7.5
Substation drainage and fire system works	• Fire system failures pose operational and safety risk • Plant integrity risk through major erosion of substation benching	• Safety requirement to have operational fire systems • Site failure costs estimated at $5 million due to ongoing ground erosion	3.4
Transmission line asset removal	• Mechanical failure of disused line asset in residential area • Environmental contamination from disused oil filled cable	• Public safety impact of asset failure in residential zone • Non-compliance with EPA regulations	2.5
General asset deterioration and failure issues			*29.3*
Refurbishment projects - isolators	• Operational safety risk (operational of plant) • Reduction of useful life and replacement costs • Extra cost of site attendance and manual operation	• Approximately 30 per cent of all system isolators are faulty (462 of 1211 units) • Premature replacement costs estimated at $14 million (50 per cent failure rate in 5 years) • Additional safety risk and reliability impacts	9.9
Substation / communications building security works and structural repairs (33 sites)	• Physical security risk of vandalism and theft • Building structural failure with damage to internal control systems and potential loss of supply impacts	• 1 in 10 year structural failure requiring replacement of equipment (estimated impact $3.5 million), loss of supply and extended outages • Prioritised by building type, location and condition (i.e. degree of structural faults)	2.0
Refurbishment	• Reduction in useful	• Approximately	5.1

Refurbishment Project Works	Risk Impacts	Timing Drivers	Cost Estimate ($m)
projects - transformers	asset life through faulty cooling systems and oil leaks	20 per cent of transformer population have life shortening defects (40 of 185 units) • Premature replacement costs estimated $22.5 million (25 per cent failure rate in 10 years)	
Refurbishment projects – gas insulated switchgear	• Major failure of GIS plant requiring asset replacement • Environmental contamination • Outage and reliability impacts	• Loss of supply to critical CBD 275 kV injection points • Potential for significant SF6 gas uncontrolled release • Emergency response and containment costs • Unscheduled outage impacts • Estimated replacement cost on failure of $12.5 million	5.0
Plant overhaul – battery chargers	• Operational risk through reduction of secondary systems reliability (protection) • Reliability impacts	• Approximately 15 per cent of all system battery chargers faulty or end-of-life (58 of 430 units) • Defect maintenance costs escalating ($6.9 million over 5 years)	4.8
Transmission line towers structural repair	• Operational and Safety risks • Impacts of unstable tower collapse	• Public safety impact • Tower collapse and associated emergency response costs estimated at $9.5 million • Associated reliability and outage impacts	2.4

<u>Impact of 10 per cent probability of exceedance demand forecast</u>

The adoption of the 10 per cent demand forecasts has deferred a number of major substation replacement projects (where timing is linked to demand growth). A number of known asset defects at these sites were scheduled to be addressed through these replacement works. Consequently, those defects that now present an unacceptable risk if delayed until the deferred project completion date will now be addressed as operational refurbishment projects. The additional operational refurbishment requirements are as follows:

Keith substation ($1.2 million)

- Refurbishment of Isolators

- Transformer Minor Refurbishment
- Replacement of Battery Chargers
- Earthing Remedial Works

Kincraig substation ($0.8 million)

- Refurbishment of Isolators
- Transformer Bund Refurbishment Oil Separation Installation
- Earthing Remedial Works

Summary

In summary, there are a number of inaccuracies in the AER's assessment of ElectraNet's operational refurbishment forecast that should be addressed:

- the operational refurbishment forecast is based on efficient packages of maintenance works based on specifically identified asset risks, rather than defect rates;
- there is no double counting of operational refurbishment expenditure in ElectraNet's opex forecasts;
- it is not prudent to defer these works, which address identified high priority asset risks and essential transmission line condition assessment works; and
- costs, risks and timing requirements have been explicitly considered in the identification, assessment and prioritisation of these projects;

The deferral of a number of major substation rebuilds (each with an augmentation component) as a consequence of the adoption of the 10 per cent probability of exceedance demand forecast has resulted in a minor increase in operational refurbishment requirements.

ElectraNet's revised proposed operational refurbishment forecast is set out in Table 7-4.

Table 7-4 Revised operational refurbishment expenditure ($m 2012-13)

	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Draft Decision	8.8	9.4	9.5	9.6	9.7	**47.0**
Revised Revenue Proposal	12.4	15.3	15.2	12.5	11.3	**66.8**

7.5.4 Network Optimisation

AER Draft Decision

The AER in its Draft Decision did not approve network optimisation as a new operating expenditure category and rejected the forecast allowance of $13.3 million ($2012-13). The AER provided the following reasons for this decision:

> "ElectraNet identified network optimisation opex as a one-off cost that applies to only the 2013–18 regulatory control period and that is expected to defer capital augmentation, but it did not demonstrate the economic case for the costs or benefits."[147]
>
> "This type of expenditure is not a step change for new circumstances. Rather, the AER's revealed costs (top down) forecast provides for the expenditure as business-as-usual expenditure in an efficient base year."[148]
>
> "…if ElectraNet were to demonstrate the network optimisation projects have an overall positive net present value, then its opex allowance should not include the $13.3 million expenditure because the program will effectively fund itself over time."[149]
>
> "…the AER found the proposed new opex category, network optimisation, does not meet the opex criteria."[150]

ElectraNet's Response

ElectraNet does not agree with this assessment, and believes the removal of this allowance will provide inadequate resources to enable ElectraNet to meet the opex objectives in the Rules and recover its efficient costs. ElectraNet addresses each of the above issues in turn.

<u>Economic case</u>

The Draft Decision states: [151]

> "ElectraNet identified network optimisation opex as a one-off cost that applies to only the 2013–2018 regulatory control period and that is expected to defer capital augmentation, but it did not demonstrate the economic case for the costs or benefits. The AER asked ElectraNet to provide evidence of the $13.3 million capex–opex trade-off and to identify the capital deferrals and costs of these projects. In response, ElectraNet provided a single example of the Bungama–Hummocks 132 kV line, for which it proposed the benefit is the deferral by seven to nine years of $191 million of capex augmentation, from an upfront opex cost of $650 000. While this deferral is a good example, ElectraNet did not quantify the net present value of the remaining $12.65 million of the forecast network optimisation opex, show the timing of the remainder of the deferrals, or identify how these deferrals link to the capex program and forecast."

Information previously provided to the AER has identified that the proposed network optimisation program includes two components:[152]

- Minor substation primary plant and secondary systems works to remove "bottlenecks" and similar minor expenditure on transmission lines to improve network transfer capability.
- Minor works to address transmission line non-compliance issues.

As discussed below, in its revised Regulatory Proposal ElectraNet does not propose to include an amount in the network optimisation category for the first component (removal of bottlenecks to improve network transfer capability), but has retained an amount in the

147 AER, Draft Decision, page 285.
148 AER, Draft Decision, page 285.
149 AER, Draft Decision, page 286.
150 AER, Draft Decision, page 155.
151 AER, Draft Decision, page 285 (footnotes from original omitted).
152 For example ElectraNet response to AER information request RP 24.

network optimisation category for the second component (works to address transmission line non-compliance issues).

Component 1: Expenditure to remove bottlenecks

ElectraNet has reviewed its originally proposed network optimisation program in the light of subsequent information on long-run demand trends, and the revised demand forecasts[153] on which the capex forecast of the revised Revenue Proposal is based. This review has revealed that the potential benefits of a number of the network optimisation initiatives are unlikely to be realised in the 2013-2018 regulatory period and therefore the proposed expenditure on these initiatives has been deferred.

ElectraNet has also reviewed its proposed network optimisation program in light of the subsequent publication in December 2012 of the AER's Final Electricity Transmission Network Service Provider Service Target Performance Incentive Scheme (STPIS). The AER has in its revised STPIS introduced a new network capability component that is aimed at providing incentives for TNSPs to undertake minor works that improve transmission capability at times when market participants and network users place greatest value on this additional capability.

As a result of this review ElectraNet intends to remove all of the initiatives that are aimed at improving network transfer capability from its revised Revenue Proposal and instead will be seeking to have the new network capability component of STPIS applied to ElectraNet in the 2013-2018 regulatory control period.

Component 2: Expenditure to address transmission line non-compliance issues

Having removed the first component of the proposed network optimisation expenditure in the revised Revenue Proposal, this will leave only the minor works to address transmission line non-compliance issues in the forecast (with estimated cost of approximately $4.9 million of the original total of $13.3 million). These works are proposed to remediate only high risk low hanging transmission line spans with clearance violations of 1 metre or more, and a proportion of spans with clearance violations of between 0.5 and 1 metre.

The driver for these works is public safety and compliance with mandatory minimum clearance heights for aerial transmission lines as set out in the Regulations under the South Australian Electricity Act. As set out below, the expenditure for these works is not currently provided for in the AER's top down forecast and it is properly characterised as once-off expenditure that is not represented in the base year costs.

<u>Expenditure not provided in AER top down forecast</u>

The Draft Decision states:[154]

> "This type of expenditure is not a step change for new circumstances. Rather, the AER's revealed costs (top down) forecast provides for the expenditure as business-as-usual expenditure in an efficient base year. The TNSP's proposed network optimisation is part of a core business objective that is a business-as-usual practice for any efficiently operated business. It is not driven by an exogenous factor or business restructure".

153 The basis of connection point demand forecasts in the revised Revenue Proposal is changing from peak demand forecasts to 10 per cent probability of exceedance forecasts.

154 AER, Draft Decision, page 285, 286.

This statement is incorrect. While the type of expenditure is not driven by a new external obligation, it is clearly not allowed for in either the 2010-11 base year or in the AER's substitute opex forecast.

The identification of the compliance issue, and consequently, the ability to rectify the non-compliance, has only come about recently as a result of new technology which permits an aerial laser survey of overhead transmission networks to be undertaken on a cost effective basis.

As has been recognised internationally, transmission networks are increasingly facing discrepancies between historic design assumptions and actual field conditions given changes in conditions in the decades since networks were originally established. The North American Electricity Reliability Corporation issued an alert in October 2010 requiring transmission entities across North America to assess and address this identified discrepancy risk across the 700,000km network, utilising newly available data collection and assessment technologies.[155]

ElectraNet has completed an aerial laser survey of its entire overhead transmission line network utilising these newly available data collection and assessment technologies. In doing so ElectraNet incurred operating expenditure, none of which was included in the 2010-11 base year.

ElectraNet has completed further analysis of the aerial laser survey data to identify transmission line spans that require remediation works to meet public safety and legal compliance requirements. None of these expenditures are allowed for in projecting forward the revealed efficient costs of the 2010-11 base year. They need to be considered as a once-off step-change requirement. Once corrected, these clearances can then be monitored and managed as a business as usual activity from that point onward.

ElectraNet regards the new information obtained from the aerial laser survey data as constituting a change in circumstances, as noted in the AER's definition of a 'step change':[156]

> "Step changes allow additional funding where the service provider faces a new requirement or change in circumstance requiring it to undertake additional expenditure that was not accounted for in the base year".

One of the defining characteristics of transmission networks is the lumpy nature of expenditure as the type and volume of required works vary over time (especially compared to distribution networks). This is a key reason why trending forward historical costs without adequate consideration of changes in cost drivers risks providing an inadequate expenditure allowance and, therefore, inefficient outcomes.

Addressing the revealed public safety risks is an example of the lumpy nature of opex requirements that needs to be recognised in the AER Final Decision.

<u>Program should fund itself</u>

The Draft Decision states:[157]

> "The Rules framework incentivises programs of work that aim to increase the use of existing infrastructure. In fact, the AER recently proposed changes to the Service Target Performance

155 North American Electric Reliability Corporation, Facility Ratings Methodology Alert to Industry, 7 October 2010.
156 AER, Draft Decision, page 38.
157 AER, Draft Decision, page 286.

> Incentive Scheme (STPIS) that incentivise this type of program through a network capability component. However, if ElectraNet were to demonstrate the network optimisation projects have an overall positive net present value, then its opex allowance should not include the $13.3 million expenditure because the program will effectively fund itself over time. Importantly, ElectraNet is not precluded from spending its opex allowance on this program and recovering the benefits over time through the efficiency benefit sharing scheme (EBSS) and STPIS."

This statement no longer applies to the reduced network optimisation program ElectraNet intends to include in its revised Revenue Proposal as Component 1 (expenditure to remove bottlenecks) has been removed from the network optimisation category.

However, the statement also appears to misunderstand the nature of the AER's new network capability incentive which is based on the TNSP applying for additional funds on a prioritised cost-benefit basis to undertake and be rewarded for approved network capability incentive expenditures.

Furthermore, the AER's statement also ignores the fact that under existing arrangements, while financial incentives apply to improve outage performance, a TNSP receives no benefit from releasing additional capacity under system normal conditions, nor does it achieve any operational expenditure savings from removing constraints on the network. In fact, the TNSP would face a disincentive to allocate expenditures to such works if no specific allowance was provided, as it would result in a penalty under the EBSS.

For the reasons outlined above, ElectraNet does not agree with the AER that the proposed expenditure in relation to network optimisation does not meet the opex criteria.

Based on the field data now collected, ElectraNet has completed initial low span analysis for its transmission line assets. This analysis has enabled ElectraNet to identify and prioritise all network low span remediation works according to safety and compliance risk, in accordance with the assessment framework established under its Asset Management Plan, in order to address this risk.[158]

It is noted that the ability for ElectraNet to manage these known safety and compliance risks will become more critical under the 10 per cent probability of exceedance demand forecasts as the network will become more heavily loaded for the same design capacity.

ElectraNet submits that the expenditures proposed on network optimisation specifically address the applicable operating expenditure objectives in the Rules, namely: to maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.[159].

The works contained within the network optimisation category are directly aimed at maintaining the safety and security of the transmission system, as noted above.

ElectraNet's revised proposed network optimisation forecast is presented in Table 7-5.

Table 7-5 Revised network optimisation expenditure ($m 2012-13)

	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Revised Revenue Proposal	0.8	1.2	1.2	1.2	0.5	**4.9**

158 ElectraNet, *Asset Management Plan,* May 2012, Appendix I, Low Span Priority Decision Process.
159 Rules, clause 6A.6.6(a)(4)

7.5.5 Superannuation Contribution Shortfall

AER Draft Decision

The AER did not approve ElectraNet's proposed superannuation 'top up' to offset a forecast contribution shortfall during the next regulatory control period associated with ElectraNet's defined benefits superannuation scheme, which was prepared based on an independent actuarial estimate. The AER also concluded that any cost movements relative to the base year would be reflected in EBSS carry forward payments.[160]

ElectraNet's Response

ElectraNet does not accept the AER's decision in relation to the forecast superannuation contribution shortfall. As noted in its Revenue Proposal, a proportion of ElectraNet's workforce is subject to a defined benefits superannuation scheme.

Defined benefit plans are those where the fund's rules specify the benefits to be paid and they are financed accordingly. The defined benefit plan assets are measured at fair value and the defined benefit obligation is measured on an actuarial basis discounted to present value. The difference between the fair value of the plan assets and the present value of the benefit obligation is a surplus or deficit which is recognised on ElectraNet's balance sheet.[161]

It is also noted that defined benefits schemes provide a minimum guaranteed rate of return to beneficiaries regardless of share market performance. An assumption that there is equal upside or downside is a reasonable starting point in the absence of any other information.

However, it is not a reasonable position in response to actuarial advice. The AER has effectively placed no weight on independent expert advice and instead assumed that downside and upside risk are equivalent. Accordingly, ElectraNet does not regard the AER's Draft Decision as reasonable because the AER has provided no proper basis for not accepting the opinion of an appropriately qualified expert.

The unfunded liabilities have increased in the current market environment. ElectraNet therefore faces a change in its operating environment due to exogenous factors.

ElectraNet's additional superannuation costs have been factored into its revised proposed forecast based on expert actuarial advice.[162]

7.5.6 Provisions

AER Draft Decision

The AER applied a decrement to ElectraNet's base year of $0.4m to account for the movement in provisions for future employee entitlements. The AER found that ElectraNet's historical cash costs reasonably reflect future costs with regard to employee entitlements.[163]

160 AER, Draft Decision, page 286.
161 PwC Letter, *"Accounting for Employee Entitlements – ElectraNet Pty Ltd,"* 15 January 2013
162 PwC Letter, *"Accounting for Employee Entitlements – ElectraNet Pty Ltd,"* 18 December 2012.
163 AER, Draft Decision, page 178.

ElectraNet's Response

ElectraNet does not accept the AER's Draft Decision in relation to removal of the movement in provisions associated with employee entitlements. ElectraNet notes that there is a requirement to account for employee entitlements in accordance with AASB119-'Employee Benefits.' This includes benefits payable including wages and salaries, sick and maternity leave, annual leave, long service leave and superannuation.

Provisions are used when a future obligation exists and there is the intention that goods or services will be consumed in the future to settle the obligation. Accrued liabilities arise when the goods or services have been received or supplied and that payment will occur in a subsequent period.

The 'provisions' being discussed in this instance should therefore be considered as representing accrued liabilities in this context.

Employee benefit liabilities represent accruals under general accounting principles and accounting standards and are not provisions as set out under AASB119: [164]

> "An entity shall measure the expected cost of accumulating paid absences as the additional amount the entity expects to pay as a result of the unused entitlement that has accumulated at the end of the reporting period."

Similar requirements apply under the applicable accounting standards to other long-term employee benefits, including long-service leave.[165]

It is appropriate that the costs are recognised in the year in which they are incurred even though the cash settlement may occur in a subsequent period. Failure to recognise the accrued costs would be indicative of a move toward a cash accounting system. These provisions properly constitute efficient base year expenditure for liabilities incurred, and form part of the controllable historic and forecast operating expenditure.

Applying cash basis to recognising employee entitlements will create challenges particularly in relation to the allocation of operating expenses. Furthermore, it serves no regulatory purpose because the costs cannot be avoided and must be recognised. However, recognising the costs on a cash basis is likely to create timing issues in the reported costs, which accrual accounting is designed to avoid.

For these reasons, ElectraNet strongly suggests that the AER reconsiders its approach to employee entitlements.

7.6 Step Changes – Non-controllable

7.6.1 Land tax

AER Draft Decision

The AER did not approve ElectraNet's proposed forecast for land tax of $14.7 million ($2012-13). The AER concluded that the forecast overestimated ElectraNet's land tax requirement for the 2014-2018 regulatory control period and instead substituted

164 Paragraph 16, AASB119.
165 Paragraphs 153-156, AASB119.

ElectraNet's forecast for a reduced land tax allowance of $11.8 million ($2012-13) on the basis that:[166]

- ElectraNet's land and easement acquisition forecast for the 2014-2018 regulatory control period was too high and should accordingly be substituted with a revised lower forecast for land and easement acquisition; and
- ElectraNet's proposed total land value escalator being applied as the sole escalator of its forecast land and easement portfolio with regards to land tax modelling is unreasonable. Individual growth factors for each category of land should be applied, and not the average, reducing the overall forecast for land tax.

It is also apparent that the AER has removed from its land tax forecast the land tax payable on a number of substation land parcels connected with forecast capital projects included within the capex forecast approved in the Draft Decision.

ElectraNet's Response

ElectraNet has incorporated all aspects of the approach adopted by the AER in relation to land value escalation and has updated the land tax forecast to reflect its revised proposed land and easement forecast, including the land tax payable on all required land parcels connected with forecast capital projects in the revised capital expenditure forecast.

The revised proposed land tax forecast is summarised in Table 7-6.

Table 7-6 Revised land tax forecast ($m 2012-13)

	2013-14	2014-15	2015-16	2016-17	2017-18	Total
AER Draft Decision	2.1	2.2	2.3	2.5	2.7	**11.8**
Revised Revenue Proposal	2.3	2.4	2.6	2.8	2.9	**13.0**

7.6.2 Self insurance

AER Draft Decision

ElectraNet proposed in its Revenue Proposal a self insurance allowance of $7.5 million for the 2013–2018 regulatory control period. This included $0.69 million to self insure for bushfire liability above the commercial insurance cap.

Subsequent to ElectraNet lodging its Revenue Proposal, an Australian Energy Market Commission Rule change gave TNSPs the ability to nominate additional pass through events in their Revenue Proposal. ElectraNet submitted a Pass Through Event proposal to the AER in August 2012 stating that it would no longer require self insurance against the bushfire liability risk if the AER accepts its proposed insurance cap pass through event.

The AER approved an insurance cap event as a nominated pass through event for the 2013-2018 regulatory control period. The AER's Draft Decision was to approve ElectraNet's revised total self insurance forecast of $6.8 million ($2012-13) over the 5 year period to reflect ElectraNet's reduced risk profile. [167]

[166] AER, Draft Decision, page 159.

[167] AER, Draft Decision, page 161.

ElectraNet's Response

ElectraNet agrees with the approach adopted by the AER. ElectraNet confirms that the self insurance allowance set out in ElectraNet's Pass Through Event proposal submitted to the AER in August 2012 (a total of $6.8 million over 5 years expressed in 2012-13 prices) has been reflected in ElectraNet's revised operating expenditure forecast.

An updated self-insurance resolution has been approved by the Board of ElectraNet which reflects the self-insurance allowance approved by the AER. This resolution is provided in Appendix L.

7.6.3 Insurance

AER Draft Decision

The AER did not approve ElectraNet's forecast insurance allowance, sourced from an external expert estimate provided by Marsh Pty Ltd. The AER substituted ElectraNet's 'zero based' insurance forecast with a base year extrapolated forecast for the 2013-2018 regulatory control period.[168]

The AER noted that insurance costs do not necessarily follow different escalation profiles and therefore should be included in the base year forecasting assessment approach. The AER also observed three apparent drivers for insurance premiums in the Marsh analysis, namely change in exposure, inflation and market factors, likening the network growth factored into the opex forecast to 'exposure', and concluding that the 'market factor' is the only point of difference between the AER base year extrapolated forecast and Marsh's estimate.

ElectraNet's Response

ElectraNet does not agree with the AER's decision to substitute ElectraNet's zero based insurance forecast for a forecast using a revealed costs (base extrapolated) approach. ElectraNet notes the AER determined in the recent Draft Decision for Powerlink that; [169]

> "The AER considers Powerlink is a price taker in a global insurance market. Using independent actuarial advice to develop insurance cost forecasts will take into account the most up to date information which impacts insurance premiums. The AER has previously accepted insurance cost forecasts on the basis of actuarial advice prepared for TNSPs, rather than extrapolating base year data."

Significantly, in Powerlink's recent Draft Decision the AER also noted that Powerlink's rapid increase in insurance costs is in part driven by the rise in insurance services consumer price index (CPI).[170.]

As ElectraNet is similarly a price taker in the global insurance market, this would suggest an approach using base year insurance costs extrapolated by all groups CPI, as adopted by the AER in ElectraNet's Draft Decision, will not reasonably reflect ElectraNet's future insurance costs. Furthermore, the EBSS cannot provide efficient incentives to ElectraNet if the insurance allowance does not keep pace with the insurance market.

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168 AER, Draft Decision, page 160-161.

169 AER, *"Powerlink Transmission Determination 2012-13 to 2016-17 – Draft Decision,"* November 2011, page 196.

170 AER, *"Powerlink Transmission Determination 2012-13 to 2016-17 – Draft Decision,"* November 2011, page 196.

Consistent with the approach adopted by Powerlink, ElectraNet's forecast was prepared based on independent actuarial advice from a reputable insurance broker (Marsh) and took into account the levels of coverage, claim history, risk profile, network growth and recent trends in insurance markets.

ElectraNet notes that insurance costs are driven by a number of different drivers largely beyond ElectraNet's control including;

- product demand;
- availability of capacity;
- appetite for risk exposure;
- claims history of the individual risk and across the portfolio; and
- market conditions.

ElectraNet therefore refutes the notion that changes in exposure merely equate to network growth, as exposure is dependent on a number of other factors largely beyond the control of ElectraNet, including claims history, external risk factors, and the risk profile of the sector in general.

It is considered that a zero based forecasting approach which considers ElectraNet's levels of coverage, claims history, risk profile and network growth as well as assessed changes in the global insurance market cycle will provide a more reasonable reflection of ElectraNet's realistic insurance costs over the next regulatory control period.

ElectraNet considers that the AER's Draft Decision to substitute ElectraNet's 'zero based' insurance forecast with a base-year-extrapolated forecast will not provide ElectraNet with a reasonable opportunity to recover its efficient insurance costs.

Accordingly, ElectraNet has adopted the independent expert insurance estimate provided by Marsh for the purposes of this revised Revenue Proposal.

7.6.4 Debt raising costs

AER Draft Decision

In its Draft Decision, the AER approved ElectraNet's method for determining benchmark debt raising costs, and revised ElectraNet's estimate from $6.3 million to $5.8 million ($2012-13) to account for the AER's revised RAB forecast.[171]

ElectraNet's response

ElectraNet has applied the approved methodology to update its benchmark debt raising cost allowance to reflect ElectraNet's revised proposed RAB forecast.

171 AER, Draft Decision, page 162, 163.

7.7 Base Year Forecast

7.7.1 Asset growth

AER Draft Decision

The AER did not approve ElectraNet's method for estimating asset growth. The AER considered that the approach of using depreciated regulated asset base (RAB) in the base year under-estimated the size of the network in the base year which had the impact of overestimating network growth rates over the forecast period.[172]

The AER considered an undepreciated RAB to be a more accurate base year for the purposes of calculating asset growth factors. Therefore the AER revised ElectraNet's forecast based on an undepreciated RAB value for the 2010-11 base year.

The AER also did not approve ElectraNet's capital expenditure load driven forecast. Accordingly, the AER updated the asset growth factors to reflect its Draft Decision on load driven capital expenditure.

ElectraNet's Response

Whilst ElectraNet does not necessarily agree in full with the AER's reasoning, ElectraNet has adopted the methodology for estimating asset growth as approved by the AER in preparing its revised proposed operating expenditure forecast.

These factors have been updated to reflect ElectraNet's revised capital expenditure forecast presented in Chapter 6.

7.7.2 Economies of scale

AER Draft Decision

The AER did not approve ElectraNet's proposed economies of scale factors. The AER noted that ElectraNet had revised its scaling factors for the forthcoming regulatory control period. However, the AER concluded that ElectraNet is unlikely to be less efficient in the future than currently and applied the same factors used for the current regulatory period for each cost category with the exception of direct charges.[173]

ElectraNet proposed an economy of scale factor of 100 per cent for its direct charges as direct charges have no efficiencies available as they are externally driven and directly proportionate to asset growth. The AER noted that the large majority of ElectraNet's direct charges are related to land tax and as land tax has been forecast using a zero based methodology and therefore does not require a scaling factor.

The AER determined that for the remaining direct charges an economy scale factor of 25 per cent be applied as direct charges fall within the maintenance support category.

ElectraNet's Response

ElectraNet does not accept the AER's proposed economies of scale factors. ElectraNet notes that its proposed economies of scale factors are consistent with those approved in

172 AER, Draft Decision, page 153.
173 AER, Draft Decision, page 153.

the AER's recent Powerlink Transmission Determination 2012-2017. In that decision, the AER determined that:[174]

> "Powerlink's proposed economies of scale factors are largely consistent with those applied by other TNSPs in recent AER transmission determinations. The AER thus is satisfied Powerlink's proposed economies of scale factors reasonably reflect the operating expenditure criteria."

ElectraNet believes the scaling factors applied in its Revenue Proposal are reasonable and, in ElectraNet's case, relatively conservative. The characteristics of ElectraNet's operating environment, including small network scale, low customer density, low load factors and unique topology in comparison with other NEM TNSPs mean it is more challenging for ElectraNet than some TNSPs to drive further scale efficiencies.

ElectraNet also disagrees with the AER's Draft Decision regarding economies of scale factors for asset growth. Whilst, as the AER notes, direct charges fall within the maintenance support category, direct charges are externally driven and proportionate to asset growth (including telecommunication licence fees, for example) and therefore should retain the existing scaling factor of 100 per cent. There is no basis for assuming that direct charges such as taxes and rates will increase by a factor of only 25 per cent with the growth in the asset base.

ElectraNet has therefore applied the original scale factors proposed in its Revenue Proposal, including a 100 per cent scaling factor to all remaining direct charges not forecast using a zero-based methodology in its revised proposed forecast.

7.7.3 Labour and materials cost escalators

AER Draft Decision

The AER did not approve ElectraNet's proposed real cost escalators because it considered that they did not reasonably reflect a realistic expectation of the cost inputs required to achieve ElectraNet's operating expenditure objectives, and adopted substituted cost escalators.[175]

ElectraNet's Response

ElectraNet does not agree with the AER's decision on labour cost escalation. ElectraNet's detailed responses to the AER's Draft Decision and revised proposed real cost escalators are set out in Chapter 3 of this revised Revenue Proposal.

7.7.4 Support and network operations forecast

AER Draft Decision

The AER approved ElectraNet's forecasting approach for the asset manager support, maintenance support, network operations and corporate support allowances, based on a base-year-extrapolated (revealed costs) methodology. However, as noted above, the AER did not accept that 2011-12 (year 4) represented an efficient base year for forecasting these expenditure categories.[176]

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174 AER, "Powerlink Transmission Determination 2012-13 to 2016-17 – Final Decision," April 2012, page 162.
175 AER, Draft Decision, page 154.
176 AER, Draft Decision, page 159.

ElectraNet's Response

In accordance with the AER's Draft Decision, ElectraNet has adopted 2010-11 as its base year (year 3) to forecast the following expenditure categories:

- asset manager support
- maintenance support
- network operations
- corporate support

As explained in its Revenue Proposal, during the course of the current regulatory period ElectraNet has restructured its organisation and implemented a new chart of accounts. It has therefore taken the opportunity to realign its underlying cost centres with the opex allowances. While this does not alter the functional structure of the allowances, it does result in a revised cost profile across these established categories, and more accurately reflects the current structure of the business and its operations[177]. Accordingly, ElectraNet has again applied the new underlying cost structure in deriving its revised forecast opex allowances.

7.8 Revised operating expenditure forecast

This section presents ElectraNet's revised operating expenditure forecast for the next regulatory period. ElectraNet's revised operating expenditure forecast reflects the adjustments and approach proposed in the AER's Draft Decision with the exception of the following aspects addressed above:

- Corrective maintenance
- Operational refurbishment
- Network optimisation
- Maintenance support
- Network operations
- Asset manager support
- Corporate support
- Debt raising costs
- Operating expenditure efficiency factor
- Forecast superannuation contribution shortfall
- Movement in provisions associated with employee entitlements
- Insurance forecast
- Asset growth escalators applied
- Economies of scale factors
- Real cost escalators

ElectraNet's revised operating expenditure forecast is presented by cost category in Table 7-7.

177 ElectraNet Revenue Proposal (May 2012), page 111. For comparative purposes, costs were presented in both formats in the comparative tables and pro forma templates accompanying the Revenue Proposal.

Table 7-7 Revised forecast operating expenditure by category ($m 2012-13)

Category Adjustments	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Routine maintenance	15.0	15.5	15.7	17.0	17.8	**80.9**
Corrective maintenance	14.9	15.1	14.0	12.1	12.3	**68.4**
Operational refurbishment	12.4	15.3	15.2	12.5	11.3	**66.8**
Network Operations	8.3	8.5	8.8	9.0	9.2	**43.8**
Network Optimisation	0.8	1.2	1.2	1.2	0.5	**4.9**
Maintenance Support	10.1	10.4	10.7	11.0	11.2	**53.4**
Asset manager support	10.2	10.5	10.8	12.5	12.7	**56.7**
Corporate support	6.9	7.1	7.4	7.6	7.7	**36.8**
Total Controllable	**78.5**	**83.6**	**83.7**	**83.0**	**82.9**	**411.7**
Self-insurance	1.3	1.3	1.4	1.4	1.4	**6.8**
Network support	8.1	8.2	8.2	8.5	8.6	**41.6**
Debt raising	1.1	1.2	1.2	1.3	1.3	**6.1**
Total Opex	**89.1**	**94.3**	**94.5**	**94.2**	**94.2**	**466.2**

Further details of operating expenditure are provided in the required pro forma statements which accompany this revised Revenue Proposal.

The comparison of the operating expenditure between the AER's Draft Decision and ElectraNet's revised Revenue Proposal is presented in Table 7-8 below;

Table 7-8 Revised total operating expenditure ($m 2012-13)

Category Adjustments	2013-14	2014-15	2015-16	2016-17	2017-18	Total
AER Draft Decision	75.0	78.3	79.3	82.0	83.1	**397.6**
Revised Revenue Proposal	89.1	94.3	94.5	94.2	94.2	**466.2**

7.9 Directors' responsibility statement

In accordance with clause S6A.1.2(6) of the Rules, this revised Revenue Proposal must contain a certification of the reasonableness of the key assumptions that underlie the operating expenditure forecast by the Directors of ElectraNet.

The Directors' responsibility statement is included in Appendix A.

7.10 Benchmarking

AER Draft Decision

Under clause 6A.6.6 (e)(4) of the Rules, the AER must in deciding whether or not the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects the operating expenditure criteria, have regard to, amongst other things:

> "benchmark operating expenditure that would be incurred by an efficient Transmission Network Service Provider over the regulatory control period."

The AER compared the level of ElectraNet's historical operating expenditure against other TNSPs by using ratio analysis to form a view as to the efficiency of ElectraNet's historical costs.[178] In considering an efficient benchmark operating expenditure, the AER used load density to normalise the results between TNSPs to allow for variations in network efficiency associated with the size and density (megawatts per kilometre of line) of the network.[179]

ElectraNet's Response

ElectraNet does not agree that benchmarking of ElectraNet's costs against other TNSP's within the NEM using the measures applied by the AER necessarily provides an appropriate measure against which to assess ElectraNet's efficient costs for the next regulatory period.

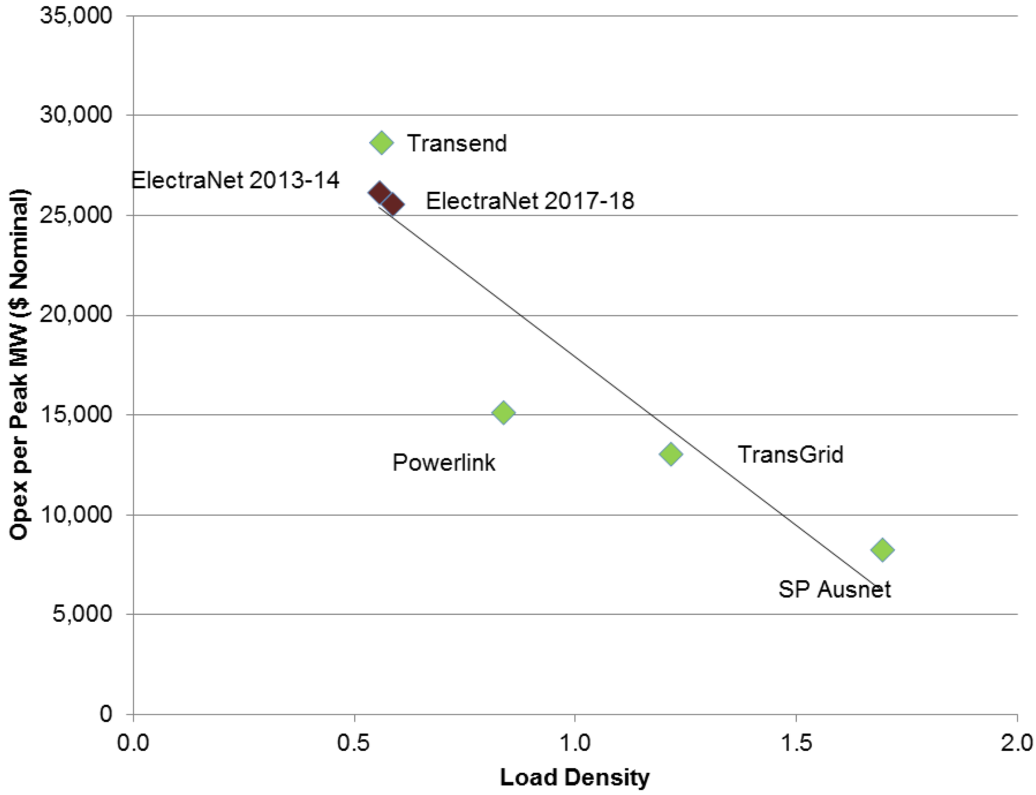
As noted in the Revenue Proposal, key characteristics drive a relatively higher level of efficient costs in South Australia in comparison with other NEM TNSPs for the delivery of electricity services including:

- Scale – the overall size of the network and smaller population limit the scope for economies of scale in service delivery relative to larger networks;
- Customer density – South Australia has the lowest energy density in the NEM, reflecting the smaller population and large geographical size, increasing the amount of network that must be maintained to supply each customer;
- Load factor – South Australia has the lowest load factor in the NEM, as measured by maximum demand relative to average consumption, increasing the level of capacity to be maintained to deliver each unit of energy, pushing up unit costs; and
- Topology – given the spread of load, the network has a large number of substations that must be maintained for its size relative to comparable networks, and includes a range of smaller voltage assets more typically found in distribution systems (for example, long 132 kV radial lines servicing country areas) increasing the cost of transmission services.

[178] AER, Draft Decision, page 287.
[179] AER, Draft Decision, page 287.

Figure 7-6 below showing ElectraNet's forecast opex to peak demand ratio for the forecast period demonstrates that ElectraNet's operating expenditure compares favourably with that of like TNSPs for the same period.

Figure 7-6 Forecast opex to peak demand ratio 2013-2018 ($ nominal)



ElectraNet will continue to work with the AER to develop more appropriate benchmarking measures that account for the inherent differences between TNSPs. However, for the reasons outlined in this revised Revenue Proposal, ElectraNet regards the proposed operating expenditure as fully satisfying the Rule requirements.

8. Cost of Capital

8.1 Summary

Chapter 9 of ElectraNet's Revenue Proposal (May 2012) sets out the methodology applied to determine the Weighted Average Cost of Capital (WACC).

In its Draft Decision, the AER approved ElectraNet's proposed method for determining the WACC (page 164). Specifically, the AER:

- Approved ElectraNet's proposed averaging period for calculating the nominal risk free rate and debt risk premium (page 164);
- Adopted the proposed parameter values, methods and credit rating determined by the AER in the 2009 WACC review, including the equity beta, market risk premium, gearing level and assumed value for the utilisation of imputation credits (page 168);
- Approved ElectraNet's proposed approach to estimate the debt risk premium (page 169); and
- Adopted a 10-year inflation forecast (page 171).

The AER has calculated a WACC using an indicative 20-day averaging period ending 19 October 2012[180] of 7.11 per cent (nominal vanilla). ElectraNet recognises that the risk free rate and debt risk premium will be updated for the AER's final determination using the approved averaging period nominated by ElectraNet on a confidential basis.

Subject to these changes in the final determination, ElectraNet has incorporated all aspects of the AER's Draft Decision on WACC in its revised Revenue Proposal.

Given that the averaging period which has been agreed with the AER will be used to determine the final WACC, for simplicity ElectraNet has applied the market parameters calculated by the AER in its Draft Decision as proxy figures for the purposes of this revised Revenue Proposal.

The following sections present ElectraNet's response to a number of matters raised in the Draft Decision.

8.2 Debt Risk Premium

AER Draft Decision

The AER approved ElectraNet's proposed approach to determine the debt risk premium (DRP) including:

- Defining the benchmark bond as a 10 year Australian corporate bond with a BBB+ credit rating, and using the Bloomberg BBB rated fair value curve to estimate the (base) seven year DRP; and
- Extrapolating the Bloomberg BBB rated seven year fair value curve to a 10 year maturity (consistent with the definition of the benchmark bond) using paired bond analysis.

180 AER, Draft Decision, page. 166.

The AER also approved ElectraNet's proposed paired bonds extrapolation method, including the selection criteria used to choose the paired bonds.

However, the AER noted apparent anomalies in the application of the selection criteria for paired bonds included in the extrapolation sample based on the analysis undertaken for ElectraNet by PwC[181]. In particular:

- The inclusion of the paired Telstra bonds in the sample, having an A credit rating by Standard and Poors at the time of the AER's Draft Decision, appears inconsistent with PwC's sample criteria, which include only bonds with a BBB, BBB+ or A- credit rating by Standard and Poors (page 169); and
- The inclusion of a pair of fixed rate Stockland bonds with maturity dates of 2015 and 2020 in the sample appears incorrect given the existence of a Stockland bond maturing in 2016 which is more consistent with PwC's selection criteria (page 169).

Accordingly, the AER excluded the Telstra bonds and amended the Stockland pair in the paired bond sample in applying ElectraNet's proposed extrapolation method to determine the DRP published in its Draft Decision. This resulted in the calculation of an amended DRP value of 3.34 per cent.

The AER also noted that it has commenced an internal review into alternatives to the Bloomberg fair value curve. This will be subject to a public consultation process consistent with the views expressed by the Australian Competition Tribunal, and any new method is not expected to be implemented in time for ElectraNet's 2013-2018 regulatory control period.

ElectraNet Response

ElectraNet accepts that the adjustments applied by the AER to the paired bond sample used to extrapolate the Bloomberg BBB rated seven year fair value curve are consistent with its proposed methodology as at the time of the Draft Decision. It is noted that the DRP will be updated based on the agreed averaging period at the time of the final decision. For this purpose, ElectraNet will submit its updated DRP calculation to the AER at the conclusion of the agreed averaging period.

For simplicity, ElectraNet has adopted the revised DRP value determined by the AER in its Draft Decision of 3.34 per cent as a proxy figure for the purposes of this revised Revenue Proposal.

<u>Public Submissions</u>

The Energy Users Association of Australia (EUAA) and the Energy Consumers Coalition of South Australia (ECCSA) each made submissions in response to ElectraNet's Revenue Proposal dealing with the DRP issue. ElectraNet responds briefly to these submissions below.

In relation to the EUAA submission, as the AER noted in the Draft Decision[182], the EUAA submission was incorrect in stating that in its final determination for Powerlink the AER had moved away from measuring the DRP by reference to the Bloomberg curve and had calculated the DRP from a sample of Australian corporate bonds.

181 *ElectraNet: estimating the debt risk premium*, PricewaterhouseCoopers, May 2012
182 AER, Draft Decision, page 170

In the Powerlink determination the AER accepted Powerlink's revised Revenue Proposal to estimate the DRP using the extrapolated Bloomberg BBB rated fair value curve.[183] The AER noted that there may be other methodologies that could be used to estimate the DRP and indicated that the AER would begin an internal review of alternative methods to estimate the DRP and conduct a consultation process.[184]

The EUAA submission is correct in noting that the Australian Competition Tribunal has indicated in recent decisions that if the AER were to move away from reliance on the Bloomberg curve it should develop any alternative methodology in consultation with regulated entities and other interested parties.[185] The Tribunal gave these indications in January 2012, before the Powerlink final determination in April 2012.

The EUAA submission also states that "the ACT decision did not say that the method used by the AER is inappropriate or unreliable in estimating the DRP". It is unclear which decision of the Tribunal the EUAA submission is referring to. Certainly in the most recent Tribunal cases involving the AER's measurement of the DRP, the Tribunal has determined that the AER's measurement has been in error and it is not correct to characterise these decisions as relating to procedural fairness as the EUAA submission does.[186]

The EUAA submission raises issues as to the liquidity of the Bloomberg fair value curve and transparency as to its methodology and data set.[187] The PwC methodology deals comprehensively with these issues. The PwC report sets out the method that PwC uses to test for the quality of the data and concludes based on the testing carried out that the data sources relied on could be said to be reflective of market opinion.[188]

The PwC report also sets out the cross-check that it applies to the extrapolated Bloomberg curve based on the available market data using econometric techniques. PwC found a close correspondence between the extrapolated Bloomberg estimate and PwC's own econometric estimates. PwC therefore recommended that the extrapolated Bloomberg curve be applied to estimate the DRP.[189]

The EUAA submits that Ofgem has discontinued use of the Bloomberg fair value curve because Ofgem has found it unreliable.[190] ElectraNet understands that Ofgem has not historically used Bloomberg to measure the cost of debt. In any case, ElectraNet notes that the measure selected by Ofgem (iBoxx) has tracked Bloomberg reasonably accurately, often providing a higher measure of the cost of debt. This is demonstrated by the figure below, extracted from Ofgem's decision document on its next transmission price control.

183 AER, *Powerlink Transmission Determination 2012-13 to 2016-17: Final Decision*, page 32, 34, 179, 181- 185.

184 AER, *Powerlink Transmission Determination 2012-13 to 2016-17: Final Decision*, page 34.

185 See for example the comments of the Tribunal in *Application by APT Allgas Energy Limited (No 2)* [2012] ACompT 5, [97] and [115] where the Tribunal noted: "In the longer term, as the Tribunal has said, it is open to the AER to adopt a different methodology. Consideration of the proper composition of the comparison sample of bonds, the methodology for deciding on the appropriate sample of bonds and the relevance of these bonds to its task should be undertaken by the AER in consultation with interested parties across the spectrum of entities in the industries it regulates, consumers of their services and other interested parties".

186 In *Application by APT Allgas Energy Limited (No 2)* [2012] ACompT5 the Tribunal determined that the AER's decision to reject sole reliance on the extrapolated Bloomberg curve and to determine the DRP based on an average of the APA bond and the extrapolated Bloomberg curve was in error. The Tribunal reached similar conclusions in the Envestra cases (*Application by Envestra Limited (No 2)* [2012] ACompT 4, and *Application by Envestra Limited (No 2)* [2012] ACompT 3).

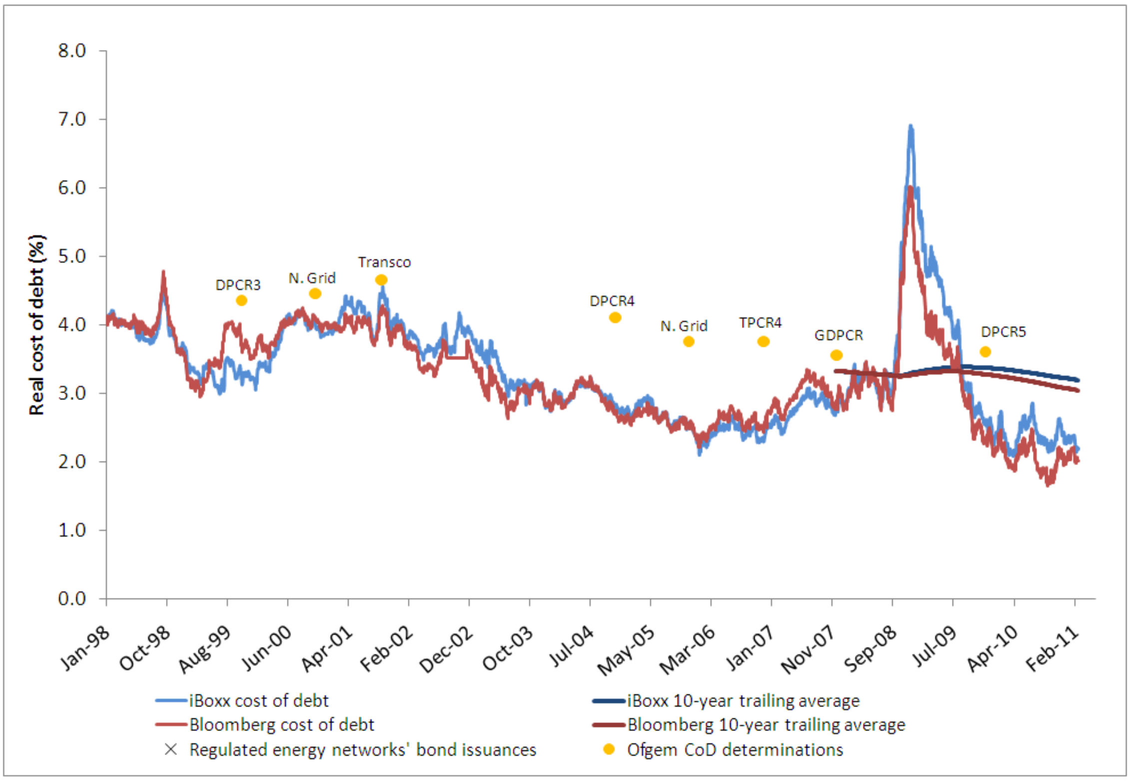
187 Energy Users Association of Australia, *EUAA Submission on ElectraNet's Revenue Proposal for 2013-14-2017-18*, page 20.

188 PwC, *ElectraNet: Estimating the Benchmark Debt Risk Premium*, May 2012, page 17-20.

189 PwC, *ElectraNet: Estimating the Benchmark Debt Risk Premium*, May 2012, page- 23-28.

190 Energy Users Association of Australia, *EUAA Submission on ElectraNet's Revenue Proposal for 2013-14-2017-18*, page 20.

Figure 8-1: Comparison of Bloomberg and iBoxx methods[191]



In relation to the ECCSA submission, ECCSA submits that reliance on the Bloomberg fair value curve requires interpolation and extrapolation of a non-transparent data set based on few data inputs.[192] As discussed above, the PwC report sets out in detail the analysis PwC conducted in order to determine that the Bloomberg fair value curve should be used to calculate the DRP.

The methodology adopted by PwC addresses the concerns raised by ECCSA as to the extrapolation of the Bloomberg curve and the volume and quality of the data sitting behind the estimate of the DRP.

ECCSA includes in its submission a table which it asserts sets out the actual DRPs for the parents of the entities listed in the table.[193] ElectraNet has not reviewed these values in detail but notes the following:

- It is not appropriate to compare an embedded implied debt margin with a forward looking margin based on current market conditions;
- It is not surprising that the DRP values in the table may be below the cost of debt contained in ElectraNet's Revenue Proposal given that a DRP which reflects market conditions at a given time may be significantly different from (higher or lower than) the average of the DRP for embedded debt.

191 Ofgem, Decision on Strategy for the Next Transmission Price Control, Ref: 46/11, 31 March 2011, page 50.
192 Energy Consumers Coalition of South Australia, SA Electricity Transmission Revenue Reset: A Response by the Energy Consumer Coalition of SA, August 2012, page 29.
193 Energy Consumers Coalition of South Australia, SA Electricity Transmission Revenue Reset: A Response by the Energy Consumer Coalition of SA, August 2012, page 29, 30.

8.3 Risk Free Rate

AER Draft Decision

The AER has approved ElectraNet's proposed averaging period to calculate the nominal risk free rate on a confidential basis, in accordance with Rules 6A.6.2(c)(2)(iii). The risk free rate has been calculated using the AER's established methodology based on the yield on 10 year Commonwealth Government Securities (CGS).

For the purposes of its Draft Decision, the AER used an indicative 20 day averaging period ending 19 October 2012 in the calculation of this parameter, which results in a risk free rate of 3.03 per cent. It is noted that the risk free rate will be updated based on the agreed averaging period at the time of the final decision. For this purpose, ElectraNet will submit its updated risk free rate calculation to the AER at the conclusion of the agreed averaging period.

For simplicity, ElectraNet has adopted the revised risk free rate determined by the AER in its Draft Decision of 3.03 per cent as a proxy figure for the purposes of this revised Revenue Proposal.

8.4 Inflation Forecast

AER Draft Decision

The AER has accepted ElectraNet's proposed method for forecasting inflation, consistent with that previously adopted by the AER, based on a geometric average of the RBA's short-term inflation forecasts extending out two years and the mid-point of the target range for the remaining eight years.

The AER has adopted an inflation forecast of 2.50 per cent per annum for the purposes of its Draft Decision, reflecting the latest RBA forecasts.

ElectraNet Response

As the AER intends to update its inflation forecast at the time of its final decision, ElectraNet has applied the AER's Draft Decision inflation forecast of 2.5 percent per annum for the purposes of this revised Revenue Proposal.

8.5 Overall rate of return

As noted in ElectraNet's Revenue Proposal (May 2012), the assessment of an adequate rate of return is of critical importance to ElectraNet as it directly affects the incentive for the owners to undertake investments in the network which, in turn, impacts outcomes for customers.[194] As also noted in ElectraNet's Revenue Proposal, in recognising the increasing community concern over electricity price impacts, ElectraNet worked hard to prepare a Revenue Proposal that delivers a customer price outcome from 2012-13 to 2017-18 in line with movements in CPI.[195]

194 ElectraNet, Revenue Proposal, page 124.
195 ElectraNet, Revenue Proposal, page 1.

ElectraNet considers that the proxy post-tax nominal vanilla WACC of 7.11 per cent represents a low rate of return, particularly in light of current market conditions. In recently completed regulatory determination processes and in determination processes that are currently underway, service providers have put before the AER considerable material to demonstrate that, in current market conditions, the measurement of the cost of capital parameters based on historic practice is leading to what appear to be aberrantly low WACC figures, specifically, low cost of equity figures.[196]

ElectraNet has adopted what it considers to be a reasonable approach to the cost of capital. ElectraNet recognises that the Rules "lock in" particular values that are in part responsible for reducing the overall regulated revenue amount, including a fixed value of 0.65 for gamma, and a fixed MRP value of 6.5 per cent. While ElectraNet considers that a higher cost of capital than that set out in the AER's Draft Decision is justifiable, ElectraNet has not sought to depart from the AER's traditional manner of calculating the WACC.

Nonetheless, ElectraNet remains concerned that a regulated rate of return of about 7 percent is not reflective of the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by ElectraNet, and arguably would not provide ElectraNet with a reasonable opportunity to recover at least the efficient costs ElectraNet incurs in providing regulated services.

Therefore, following the conclusion of the averaging period and the calculation of the relevant parameters, consideration may need to be given to whether the resultant overall cost of capital, considered in light of the final decisions the AER proposes to make with respect to other aspects of the Revenue Proposal, is consistent with the requirements of the Rules and the Law.

196 For example, the material submitted by the Victorian gas distribution businesses in their amended access arrangement revisions in November 2012.

8.6 Revised Cost of Capital

For the purposes of this revised Revenue Proposal, ElectraNet has applied a post-tax nominal vanilla WACC of 7.11 per cent, as adopted by the AER in its Draft Decision. The key parameters and variables underlying the cost of capital calculation are summarised in Table 8-1 below, and are consistent with the values adopted by the AER in its Draft Decision.

Table 8-1: WACC parameters used for the purpose of this revised Revenue Proposal

Parameter	ElectraNet Revised Proposal
Nominal Risk Free Rate	3.03%
Inflation rate	2.50%
Debt Risk Premium	3.34%
Proportion of Debt Funding	60.00%
Market Risk Premium	6.50%
Corporate Tax rate	30.00%
Value of Imputation Credits (Gamma)	0.65
Equity Beta	0.8
Nominal post-tax cost of equity	8.23%
Nominal pre-tax cost of debt	6.37%
Nominal Vanilla WACC	**7.11%**

As noted above, the final WACC parameters for the 2013-2018 regulatory control period will be determined in the AER's final decision based on market rates prevailing at the time of the approved averaging period nominated by ElectraNet on a confidential basis.

9. Regulatory Asset Base

9.1 Summary

Chapter 4 of ElectraNet's Revenue Proposal (May 2012) provides an overview of its historical capital expenditure and Chapter 7 sets out the roll forward methodology that establishes the opening Regulatory Asset Base (RAB) as at 1 July 2013.

In its Draft Decision, the AER:

- did not approve ElectraNet's proposed opening RAB of $2,099.9 million as at 1 July 2013 and determined it to be $2,077.8 million (page 172);
- adjusted the opening RAB values by asset class at 1 July 2008 by transferring $17.4 million from 'Substation primary plant' to 'Accelerated depreciation' in the proposed Roll Forward Model (RFM), consistent with the values in the approved post-tax revenue model for the 2008-2013 regulatory control period (page 178);
- reduced by $3.2 million the actual capital expenditure amounts included in the RFM for 2008-09 to 2012-13, to reflect the movement in capitalised provisions for those years (page 178);
- corrected a number of apparent input errors in the proposed RFM, resulting in a net reduction in the opening RAB at 1 July 2013 by $1.7 million (page 179); and
- indicated that it will update the RAB calculation to reflect actual 2011-12 capital expenditure in the RFM (Table 7.1, page 173).

ElectraNet has incorporated all aspects of the AER's Draft Decision in relation to the opening RAB, other than the adjustment to capitalised provisions which is addressed in Section 9.2 below.

Section 9.3 provides updated information on capital expenditure, including actual capital expenditure for 2011-12 and revised estimates for 2012-13. Section 9.4 presents ElectraNet's revised opening RAB as at 1 July 2013.

ElectraNet's updated capital expenditure forecast for the forthcoming regulatory period, which is explained in Chapter 6 of this revised Revenue Proposal, also affects the forecast RAB. Chapter 9 contains the updated RAB forecast for the 2013-2018 regulatory period.

9.2 Reversal of movements in provisions

AER Draft Decision

In its Draft Decision, the AER noted that ElectraNet's proposed actual capital expenditure for 2008-09 to 2012-13 includes capitalised movements in provisions for employee entitlements such as annual leave and long service leave.

The AER noted that the Rules require the RAB to be increased by the amount of all capital expenditure incurred during the 2008–2013 regulatory control period. The AER considered that capitalised provision movements should not be included in the RAB because ElectraNet has not yet paid out (incurred) the expenses to which the provisions relate.

On this basis, it adjusted ElectraNet's actual capex for 2007-08 to 2012-13 in the RFM to reverse the movements in capitalised provisions in the 2008-13 regulatory control period, reducing ElectraNet's opening RAB as at 1 July 2013 by approximately $3.2 million.

ElectraNet Response

ElectraNet strongly disagrees with the AER's reduction of the opening RAB by the removal of capitalised provision movements.

The Rules require that:

- The RAB must be rolled forward in accordance with clause S6A.2.1(f)(1), which states that in determining the opening value of the RAB, the previous value of the RAB must be increased by the amount of all capital expenditure incurred during the previous regulatory control period.
- Under clause S6A.2.1(f)(4), all capital expenditure added to the RAB must be properly allocated to the provision of prescribed transmission services in accordance with the TNSP's Cost Allocation Methodology.
- For the purposes of rolling forward the RAB for a transmission system, the AER may only remove from the RAB the value of an asset under the specific circumstances described in clause S6A.2.3(a).

ElectraNet interprets the AER's Draft Decision as seeking to exclude provision movements from the RAB on the grounds that it is not 'capital expenditure incurred' in accordance with clause S6A.2.1(f)(1). As explained below, however, not only is this conclusion inconsistent with the common law position and Australian Accounting Standards, but it is likely to have unintended consequences that are contrary to the national electricity objective.

For completeness, ElectraNet addresses each of the above requirements of the Rules and the practical consequences of the approach proposed by the AER in turn.

<u>Capital expenditure incurred</u>

In relation to the first of these requirements, the Rules is unequivocal that the RAB <u>must</u> be increased by the amount of all capital expenditure incurred during the previous regulatory control period. In the context of the AER's Draft Decision, the key issue is whether the provisions included by ElectraNet constitute "capital expenditure incurred".

ElectraNet understands that the AER does not disagree that employee entitlements are appropriately characterised as capital expenditure to the extent that the relevant employees are engaged in ElectraNet's capital program, however, in the interests of completeness, ElectraNet provides the following information on this issue.

The Australian Tax Office (ATO) has considered this issue in the context of a public utility that owns and operates a large distribution network.[197] In this interpretative decision, the ATO states that to the extent that expenditure is incurred on labour on-costs (being employee allowances such as leave payments, payroll tax and workers compensation) for periods when relevant employees are working on projects relating to work undertaken to

[197] Australian Tax Office, *ATO Interpretative Decision – Income Tax: Deductibility of Labour On-Costs to the Extent that Employees are Engaged on the Self-Construction of Depreciating Assets*, ATO ID 2011/43.

upgrade or expand the distribution network, the expenditure incurred on labour on-costs will be capital in nature.[198]

Having established that the labour on-costs of that part of the workforce engaged in the capital program are to be properly treated as being of a capital nature, the next question is when labour on-costs may be considered to have been "incurred".

There is High Court authority that the term "incurred" does not mean only defrayed, discharged or borne, but includes encountered, run into, or fallen upon.[199] In discussing other authorities the High Court has also noted that such authorities did not imply that a liability to pay an ascertained sum is never "incurred" until the sum becomes due and payable, or that no outgoing could be "incurred" until actual payment is made.[200] To this end the AER is incorrect to equate in the Draft Decision the term "incurred" with "paid out".[201]

This is not to say that expenditure that is no more than impending, threatened or expected is "incurred".[202] Rather, once a definite commitment to the outgoing has arisen, the outgoing is "incurred".

ElectraNet submits that the amounts capitalised in the regulatory asset base in respect of provision for employee entitlements are to be considered relevantly "incurred" costs. The requirement to pay these amounts and the quantum of the amounts to be paid is sufficiently certain such that the costs are to be considered "incurred".

For example, annual leave is accrued continuously on a pro rata basis as employees render services to the organisation. Similarly, long service leave entitlements are accrued based on length of service, and balances are trued up as part of ElectraNet's annual reconciliation of employee entitlements to accurately reflect outstanding amounts. Superannuation provisions are accrued in accordance with statutory requirements.

In light of the above, ElectraNet submits that it is correct to capitalise provisions for employee entitlements. In these circumstances the relevant capital expenditure is properly characterised as "incurred".

Turning to accounting standards, the Australian Accounting Standards define capital expenditure, and the recognition and measurement of costs relating to the creation or acquisition of fixed assets. ElectraNet has a statutory requirement to comply with the Australian Accounting Standards. Furthermore, the AER's *Electricity transmission network service providers Information Guidelines*, also require ElectraNet to prepare its regulatory accounts and report information in accordance with the applicable Australian Accounting Standards.

The Australian Accounting Standards provide for the capitalisation of costs including amounts (such as accrued employee benefits) attributed to an asset when it is initially recognised, as follows.

AASB 116 (Property, Plant and Equipment) prescribes the accounting treatment for fixed assets. AASB 116 notes that the principal issues in accounting for property, plant and

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198 Australian Tax Office, *ATO Interpretative Decision – Income Tax: Deductibility of Labour On-Costs to the Extent that Employees are Engaged on the Self-Construction of Depreciating Assets*, ATO ID 2011/43, page 3.

199 *Federal Commissioner of Taxation v James Flood Proprietary Limited* (1953) 88 CLR 492, 507.

200 *Federal Commissioner of Taxation v James Flood Proprietary Limited* (1953) 88 CLR 492, 507.

201 Draft Decision, page 178.

202 *Federal Commissioner of Taxation v James Flood Proprietary Limited* (1953) 88 CLR 492, 507 citing *New Zealand Flax Investments Ltd v Federal Commissioner for Taxation* (1938) 61 CLR 179.

equipment include the recognition of the assets, and the determination of their carrying amounts.

AASB 116 defines cost as follows:

> Cost is the amount of cash or cash equivalents paid or the fair value of the other consideration given to acquire an asset at the time of its acquisition or construction or, where applicable, the amount attributed to that asset when initially recognised in accordance with the specific requirements of other Australian Accounting Standards.

Paragraph 15 of AASB 116 provides that an item of property, plant and equipment that qualifies for recognition as an asset shall be measured at its cost.

Paragraph 16 defines the elements of cost as follows:

> The cost of an item of property, plant and equipment comprises:
>
> a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates;
>
> b) any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management; and
>
> c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.

Paragraph 17(a) of AASB 116 states that examples of directly attributable costs include costs of employee benefits (as defined in AASB 119 Employee Benefits[203]) arising directly from the construction or acquisition of the item of property, plant and equipment.

ElectraNet's Revenue Proposal (May 2012) recognised employee benefits not yet paid as capital expenditure incurred. ElectraNet submits that it is consistent to treat employee benefits in this manner on the basis of both the common law position and the applicable Australian Accounting Standards as described above.

ElectraNet also notes that it would be practicably difficult and administratively cost prohibitive to only capitalise employee entitlements when ElectraNet actually pays the entitlement. This is addressed in expert advice provided by PricewaterhouseCoopers (PwC), which is discussed in detail below.

<u>Allocation of capital expenditure</u>

In relation to the requirement in clause S6A.2.1(f)(4), that all capital expenditure added to the RAB must be properly allocated to the provision of prescribed transmission services in accordance with the TNSP's Cost Allocation Methodology, ElectraNet has properly attributed all capital expenditure added to the RAB in accordance with its approved Cost Allocation Methodology.

[203] The term "employee benefits" is defined in AASB 119 as: "all forms of consideration given by an entity in exchange for service rendered by employees or for the termination of employment". From other parts of AASB 119 is it clear that the following are encompassed by the term "employee benefits": paid annual leave and paid sick leave (paragraph 9); and long-service leave (paragraph 153).

In the Directors Responsibility Statement which accompanies this revised Revenue Proposal, the Directors of ElectraNet have specifically attested to this fact as follows:

> The historic capital and operating expenditure information provided in support of ElectraNet's Transmission Network revised Revenue Proposal 2013-14 to 2017-18 is drawn up and presented fairly according to the AER's submission guidelines and cost allocation guidelines, and consistent with ElectraNet's approved Cost Allocation Methodology.[204]

Removal of assets from the RAB

In relation to the third of the above requirements of the Rules relating to the removal of assets from the RAB, ElectraNet notes that the specific circumstances which would enable the removal of an asset from the RAB do not apply in this instance.[205]

Practical implications

In addition to the above assessment of the Rules and the Australian Accounting Standards, ElectraNet has sought independent advice from its company auditor PwC on the appropriate accounting treatment of capital provisions. A copy of this advice has been provided to the AER on a confidential basis. In that advice, PwC confirms that:

- ElectraNet is required to account for benefits paid to employees in accordance with Australian equivalents to International Financial Reporting Standards (AIFRS);
- The benefits paid to employees include wages and salaries, sick and maternity leave, annual leave, long service leave and superannuation (both defined benefit and contribution plans);
- Relevant Accounting standards issued by the Australian Accounting Standards Board include AASB 101 Presentation of Financial Statements (AASB 101), AASB 116 Property Plant and Equipment (AASB 116) and AASB 119 Employee Entitlements (AASB 119); and
- Under the Australian Accounting Standards, ElectraNet is required to set aside amounts to reflect accrued employee benefits with respect to annual leave, long-service leave and superannuation.

In order to comply with Australian Accounting Standard AASB116 (Property, Plant and Equipment) employee benefits form part of ElectraNet's labour rates which are calculated monthly and applied to employee activity to allocate costs to capital works and to operational activities. This allows all costs, including accrued employee benefits, to be allocated to the respective activities. Approximately 50 per cent of these costs relate to capital works.

The implication of the AER's proposal to reverse employee provisions is that ElectraNet would be required to maintain a duplicate set of transactions and corresponding financial records for the treatment of capitalised provisions for statutory purposes and regulatory purposes.

204 Appendix A - Directors Responsibility Statement, January 2013.

205 As per Rules S6A.2.1(f)(4), these circumstances include: that the asset is dedicated to a single transmission network user, the asset value exceeds $10m, and the asset is no longer contributing to the provision of prescribed transmission services.

This is contrary to accepted accounting practice, and raises a number of practical difficulties:

- cash treatment for employee benefits can only be effected as a high level adjustment, and can never practicably be applied to the relevant individual assets on a retrospective basis, resulting in undercapitalisation of some assets, and overcapitalisation of others;
- as ElectraNet's accounting systems are designed to conform with best practice in accordance with accepted accounting standards, detailed manual adjustments and system changes would be required to enact cash treatment for employee benefits;
- additional administration effort and cost would be incurred in recording transactions under two sets of rules, undertaking additional reconciliation and maintaining multiple fixed asset registers;
- this approach creates inconsistency with the treatment of contractor costs, which are purchased inclusive of accrued employee benefits;
- assets may be fully depreciated and removed from use before cash costs relevant to their construction are incurred; and
- in circumstances where cash costs incurred after the commissioning of the relevant assets can no longer be capitalised, these costs must be expensed. This would need to be reflected in an increased operating expenditure forecast.

Conclusion

The exclusion of capitalised provisions from the RAB is therefore contrary to the requirements of the Rules, and would increase the cost and complexity of financial record keeping for no obvious benefit to consumers. In particular, if employee benefits cannot be capitalised prior to commissioning of an asset, an upward adjustment will be required to ElectraNet's forecast operating expenditure to account for the reallocation of costs from capital to operating expenditure.

The national electricity objective would not be promoted if the correct allocation of costs is distorted as a result of the AER's treatment of employee entitlements. Such issues can be readily avoided by maintaining the well-accepted practice of accrual accounting for the purpose of defining capital expenditure in accordance with the Australian Accounting Standards.

ElectraNet has therefore retained capitalised provisions in its opening RAB as at 1 July 2013.

9.3 Revised capital expenditure forecast (2008-13)

AER Draft Decision

The AER noted in its Draft Decision that the roll forward of ElectraNet's asset base included estimated capex values for 2011-12 and 2012-13. The AER indicated that it will update the 2011-12 estimated capex value for its Final Decision with the actual value, and may update the 2012-13 capex value if ElectraNet's revised Revenue Proposal includes a more up-to-date estimate.

ElectraNet Response

ElectraNet has updated its revised Revenue Proposal and supporting models for actual 2011-12 and forecast 2012-13 capital expenditure. These updated values have been used to establish the revised opening RAB. The revised capital expenditure by category in the current regulatory period is shown in Table 9-1. These categories are consistent with the forecast capital expenditure for the 2013-2018 regulatory control period set out in Chapter 6.

Table 9-1 Revised capital expenditure as incurred by category ($m nominal)

Category	2008-09	2009-10	2010-11	2011-12	2012-13	Total
Augmentation	14.2	42.5	161.8	74.8	57.5	**350.7**
Connection	11.9	20.8	28.9	15.0	22.5	**99.0**
Replacement	55.3	35.0	19.2	50.0	93.1	**252.5**
Strategic land/ easements	1.2	0.2	1.2	12.1	14.9	**29.6**
Security/compliance	3.7	8.0	11.0	14.2	18.4	**55.3**
Inventory/spares	3.9	2.4	2.2	0.5	3.5	**12.5**
Business IT	6.4	5.8	7.3	6.7	13.8	**39.9**
Buildings/facilities	0.9	2.8	0.7	1.1	2.3	**7.9**
Total	**97.4**	**117.6**	**232.2**	**174.3**	**225.9**	**847.5**

ElectraNet has also prepared updated pro forma reporting templates in relation to historical capital expenditure which accompany this revised Revenue Proposal.

9.4 Revised opening Regulatory Asset Base at 1 July 2013

ElectraNet's revised opening RAB as at 1 July 2013 is $2,087.3 million compared with $2,077.8 million included in the AER's Draft Decision. The difference in opening RAB is due to:

- re-inclusion of incurred provisions of $3.2 million;
- use of actual 2011-12 capital expenditure which was not available at the time the Revenue Proposal was submitted;
- update of forecast capital expenditure for 2012-13; and
- increased escalation based on the updated inflation forecast to June 2013.

ElectraNet understands that the AER will update the roll forward of the opening RAB with actual March 2013 CPI in publishing its Final Decision.

Table 9-2 shows the revised opening RAB at 1 July 2013.

Table 9-2 Revised opening RAB at 1 July 2013 ($m nominal)

	2008-09	2009-10	2010-11	2011-12	2012-13
Opening RAB	1,311.8	1,391.6	1,495.5	1,725.7	1,868.6
Capital Expenditure as incurred	102.4	123.8	243.7	182.4	238.4
Straight line depreciation	(55.0)	(60.1)	(63.4)	(66.8)	(73.6)
Inflation adjustment	32.4	40.2	49.8	27.3	60.7
Closing RAB	1,391.6	1,495.5	1,725.7	1,868.6	2,094.1
Adjust for difference in 2007-08 actual capex (and disposals)38					(4.1)
Adjust for return on difference in 2007-08 actual capex (and disposals)39					(2.7)
Opening RAB at 1 July 2013					**2,087.3**

ElectraNet's revised closing RAB as at 30 June 2018 is presented in Chapter 12 which sets out ElectraNet's calculation of the Maximum Allowable Revenue (MAR) for each year of the 2013-2018 regulatory control period.

10. Depreciation

10.1 Summary

Chapter 8 of ElectraNet's Revenue Proposal (May 2012) provided an assessment of its allowable depreciation on assets providing prescribed services for the 2013-2018 regulatory control period.

Clause 6A.6.3 of the Rules requires that the nominated depreciation schedules must use a profile that reflects the nature of the category of assets (which must be classified into well accepted categories[206]) over the economic life of that category of assets. ElectraNet depreciated each asset category in the RAB on a straight-line basis over its economic life.

ElectraNet proposed the addition of a new asset class, 'transmission line refit', to reflect the resulting average life extension for relevant transmission lines.

In its Draft Decision, the AER:

- did not approve ElectraNet's proposed depreciation allowance of $233.6 million ($ nominal) for the 2013–2018 regulatory control period and substituted an alternative regulatory depreciation allowance of $228.1 million ($ nominal) (page 181);
- did not approve ElectraNet's proposed standard asset life of 15 years for the 'transmission line refit' asset class, and determined a standard asset life of 27 years for this asset class (page 184). The AER also proposed to rename the asset class 'Transmission lines refit—insulators replacement 2013–2018';
- approved ElectraNet's proposed weighted average method to calculate the remaining asset lives as at 1 July 2013, and updated ElectraNet's remaining asset lives as at 1 July 2013 to reflect the AER's adjustments to the RAB roll forward in the RFM (page 188);
- approved ElectraNet's proposal to accelerate the depreciation of the residual values of assets to be replaced, and reduced the amounts allocated for accelerated depreciation purposes to $3.6 million from the proposed $5.6 million to reflect reductions to ElectraNet's proposed replacement capex (page 189);
- approved ElectraNet's proposal to not depreciate its land and easement assets over the 2013-2018 regulatory control period (page 189); and
- noted that its determinations on a number of other components of ElectraNet's Revenue Proposal impact on the regulatory depreciation allowance, including forecast capex and the opening RAB as at 1 July 2013 (page 181).

Section 10.2 below addresses the AER's approach to depreciating the 'transmission lines refit – insulators replacement 2013–2018' asset class. ElectraNet's revised depreciation forecasts for the forthcoming regulatory period are set out in section 10.3.

206 Rules, clause S6A.1.3(7).

10.2 Transmission line refit asset class

AER Draft Decision

In its Draft Decision, the AER accepted the majority of ElectraNet's proposed standard asset lives, stating that they are consistent with the AER's approved asset lives for ElectraNet's current regulatory control period and are comparable with the standard asset lives approved by the AER in recent transmission determinations.

However, the AER did not accept ElectraNet's proposed depreciation schedule for the 'Transmission line refit' asset class. The AER concluded that the proposed standard life of 15 years does not reflect the economic life of the assets in this asset class, and determined an alternative standard asset life of 27 years to reflect the weighted average of the economic lives of the assets used for the forecast transmission line refurbishment works.

The AER also proposed a name change for this asset class, from 'Transmission line refit' to 'Transmission lines refit — insulators replacement 2013–2018'.

ElectraNet Response

ElectraNet has incorporated the proposed name change to the new asset class in its revised Revenue Proposal, but has not incorporated the AER's revised economic life for the 'Transmission line refit—insulators replacement 2013-2018' (TLR) asset class of 27 years.

ElectraNet submits that the AER's adoption of 27 years may reflect the technical life of the asset, but does not reflect its economic life.

It is clear that what is relevant in determining and assessing the depreciation schedules is the economic life of the relevant asset or category of assets. Clause 6A.6.3(b)(1) of the Rules states:

> "the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets."

Therefore, the relevant matter to be determined is the 'economic life' and not the 'technical life' of an asset. The economic life of an asset reflects its usefulness to the owner, and may be shorter than its technical life. Before turning to the difference between economic and technical life in this particular case, it is worth noting the AEMC's intentions in drafting the relevant Rules provisions.

In determining the Rules provisions relating to depreciation, the AEMC made the following observations:[207]

> *"The Draft Revenue Rule requires the TNSPs to propose depreciation schedules that must comply with the following principles set out in the Rules:*
>
> - *each asset (or group of assets) is to be depreciated over its economic life; and*
> - *each asset is to be depreciated only once, and the total sum of the allowed depreciation over the asset's life is to equal the initial value at which the asset entered the RAB.*

207 AEMC, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No.18, 16 November 2006, page 78, 79.

Provided the TNSP's proposed depreciation schedules complied with these two principles, the AER is to use these schedules in calculating depreciation. If they do not, the AER is able to determine schedules that do comply in calculating depreciation allowances.

This approach codifies current practice. The Commission considers that substantial prescription in the Rules in relation to depreciation would reduce the flexibility of the TNSPs and the AER to alter the depreciation approach, where such change may be warranted. The Commission also considers that the discretion to propose depreciation schedules appropriately lies with TNSPs rather than with the regulator, as it is the TNSPs that have the best knowledge of the condition and likely future utilisation of their assets."

It is clear from the AEMC's Rule determination and the drafting of the Rule itself that provided the depreciation schedules proposed by the TNSP comply with the requirements of the Rules, the AER is required to accept those depreciation schedules. Further, the AEMC recognises that TNSPs should have discretion in proposing the depreciation schedules, noting that TNSPs are best placed to determine the condition and likely future utilisation of their assets.

ElectraNet submits that its depreciation schedules conform to the requirement that the depreciation profile reflects the nature of the TLR asset class over the economic life of that asset class and that there is no relevant discretion for the AER to not approve the depreciation schedules on this basis.

In ElectraNet's Revenue Proposal, it was noted that the company's auditors, PwC, supported the proposed approach to depreciating the TLR asset class.[208] Given the support of the company's auditors and the AEMC's policy intention to provide TNSPs with discretion in relation to the choice of depreciation schedule, the AER should only amend the proposed life of the asset class if the proposal unequivocally fails to comply with the Rules provisions. As discussed below, however, this is not the case.

In relation to the TLR asset class, the AER argues that the economic life of the insulators will equate to their weighted average technical life of 27 years. The AER's view is implicitly predicated on the following assumptions:

- Once the underlying transmission line assets exhaust their extended remaining economic life, the line refit assets can be redeployed elsewhere, and therefore have a continuing useful economic life; or
- The economic life of the underlying transmission line assets will be extended so that the TLR insulators will continue to provide services throughout their technical life.

In relation to the first proposition, ElectraNet's engineering assessment is that the redeployment of the line refit assets (which predominantly comprise insulator strings and associated components) is not an economic option, based on evidence already provided to the AER. This is because:

- Installation of insulators is a time consuming and labour intensive activity, and the bulk of the cost of the line refit works is related to non-material costs which cannot be recovered in any redeployment – the value of the components account for only 20 per cent approximately of the installed cost;

208 ElectraNet, Transmission Network Revenue Proposal 2013-2018, 31 May 2012, page 121.

- The cost of dismantling, condition assessment, transport, packaging, warehousing and storage, stock control, data and documentation management, and redeployment of the assets for their expected remaining life would far outweigh the cost of procuring and installing new assets; and
- The most cost effective economic solution would be to decommission and dispose of the assets at the conclusion of the extended remaining economic life of the underlying transmission line asset.

In relation to the second proposition, it is speculative to assume that the underlying line assets will exceed their remaining economic life (as extended through the line refit projects) because there is no engineering basis for this assessment at this point in time. In particular:

- The extended remaining economic life of each refitted transmission line asset has been determined on a case-by-case basis through engineering assessment based on current available information on asset condition and risk;
- Transmission line assets comprise several groups of components, including conductors, insulators, supporting systems (i.e. structures) and subcomponents. The life of the assets provided under the TLR asset class is dependent on the lives of the underlying transmission line assets to which the refit works relate;
- In each instance, the specific condition of these individual component groups has been assessed and the expected remaining life of the transmission line asset has been determined based on the average remaining life of the next limiting component group. This is a prudent approach to assessing the remaining asset life and is consistent with accounting standards as confirmed by PwC; and
- Depreciation schedules by definition reflect the expected remaining economic life of the relevant assets based on current information. The economic life of the transmission line should be determined by its economic life, rather than the technical life of a relatively minor component, consistent with generally accepted accounting practice and the requirements of the Rules.

The difference between economic life and technical life for insulators is illustrated in Table 10-1 below, which (with the exception of final column) is also set out on page 187 of the AER's Draft Decision.

Table 10-1 Transmission line refit projects and economic asset lives

Line refit project	Project timing	Remaining life before refit (years)	Insulator type expected life (years)	Next limiting component by condition assessment	Remaining life of the next limiting component (years)	Extended end of economic life[(a)]
Line 1	2016	–1	20	Support systems (footings)	10–15	2026-2031
Line 2	2016	9	40	All	15–20	2031-2036
Line 3	2017	8	40	Support systems (towers, footings)	15–20	2032-2037
Line 4	2017	–9	40	Support systems (Towers)	15–20	2032-2037
Line 5	2016	7	40	All	15–20	2031-2036
Line 6	2017	20	40	Support systems	15–20	2032-2037

(Poles)

(a) For depreciation purposes a weighted average extended asset age of 15 years has been applied

The second column shows the timing of the relevant transmission line refit, with completion of these projects scheduled for 2016 and 2017. The technical lives of the insulators are shown in the fourth column. In all cases, the technical life is either 20 or 40 years based on the insulator type. However, the economic life of the insulator is governed by the remaining life of other transmission line components, which are identified in the next column.

In all cases, it is these components that limit the economic life of the overall transmission line, and in turn therefore the economic life of the insulators. The life extension of the transmission line is between 10 and 20 years (with a weighted average life extension period of 15 years applied for depreciation purposes across this asset category), compared to the technical life of the insulators of between 20 and 40 years. As already noted, it is the economic life that is relevant to the Rules provisions, not the technical life.

As already noted, the AER's approach assumes that the next limiting components will themselves be replaced so that the economic life of the insulators will be extended to encompass their technical life. However, as noted above, there is currently no engineering basis for this assessment.

In light of the above comments, ElectraNet has retained its proposed standard asset life of 15 years for the TLR asset class to reflect the expected remaining economic life of the refitted transmission line assets as required by the Rules.

If, contrary to ElectraNet's revised Revenue Proposal, the AER maintains its view in the Draft Decision, ElectraNet expects to propose accelerated depreciation of the residual asset value at a future date. While the amount of depreciation paid by customers would be unaffected by the AER's approach, the profile of that expenditure would be affected.

10.3 Revised Depreciation Forecast

In accordance with the accepted weighted average method, ElectraNet has updated its remaining asset lives as at 1 July 2013 to reflect its updated actual capex included in the roll forward of the RAB in the RFM, as discussed in Chapter 9.

Table 10-2 sets out the remaining lives associated with ElectraNet's asset classes.

Table 10-2 Remaining asset lives as at 1 July 2013

Asset Class	AER Draft Decision	Revised Revenue Proposal
Commercial Buildings	23.9	23.3
Communication - Civil	45.0	44.5
Communication - Other	12.0	11.7
Computers, Software and Office Machines	3.5	3.4
Easements	n/a	n/a
Land	n/a	n/a
Network Switching Centres (e.g. SCADA)	4.3	1.0
Office Furniture, Movable Plant and Miscellaneous	9.1	8.4
Refurbishment 2003-2008	4.4	4.4
Substation Primary Plant	33.3	32.8
Substation Demountable Buildings	14.4	5.6
Substation Establishment	53.3	53.4
Substation Fences	35.0	34.8
Substation Secondary Systems - Electromechanical	17.2	17.2
Substation Secondary Systems - Electronic	14.3	12.0
Transmission Lines - Overhead	31.1	30.2
Transmission Lines - Underground	36.6	34.9
Working Capital	n/a	n/a
Accelerated Depreciation	5.0	5.0
Refurbishment Projects 2008-2013	12.5	12.5
Equity raising cost - 2003 opening RAB and 2003-08 capex	38.0	38.0
Equity raising cost 2013-2018	n/a	n/a
Transmission Lines Refit - Insulators Replacement 2013-2018	n/a	n/a

ElectraNet has forecast the depreciation schedules for the 2013-2018 regulatory control period based on the opening RAB, remaining asset lives above, and revised forecast asset additions and disposals.

ElectraNet's revised regulatory depreciation for the next regulatory control period is shown in Table 10-3 The AER's PTRM has been used to calculate the regulatory depreciation allowance on a straight-line-basis, incorporating all of the proposed changes from the AER's Draft Decision with the exception of:

- The adoption of an extended standard life of 27 years for the 'transmission Line Refit' asset class, which has been maintained at 15 years; and
- Remaining asset lives, which have been updated using the approved weighted average method as above.

Table 10-3 Revised regulatory depreciation forecast ($m, nominal)

	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Straight line depreciation	81.7	92.2	107.9	118.7	123.4	**523.9**
Inflation adjustment on RAB	(52.2)	(57.1)	(60.3)	(63.8)	(66.5)	**(299.9)**
Regulatory depreciation	**29.5**	**35.1**	**47.6**	**54.9**	**56.8**	**224.0**

Table 10-4 compares the revised regulatory depreciation forecast with the AER's Draft Decision. Differences in regulatory depreciation also include the consequential impacts discussed in other relevant chapters, such as the revised capital expenditure forecast.

Table 10-4 Revised regulatory depreciation comparison ($m, nominal)

	2013-14	2014-15	2015-16	2016-17	2017-18	Total
AER Draft Decision	35.1	39.3	50.4	51.4	57.4	**233.6**
Revised Revenue Proposal	29.5	35.1	47.6	54.9	56.8	**224.0**

The reduction to the depreciation allowance relative to the Draft Decision largely reflects a reduction in commissioned asset values in years 2011-12 and 2012-13 relative to the forecast as at May 2012.

As required, ElectraNet has also provided depreciation schedules by asset class in the depreciation pro forma template accompanying this revised Revenue Proposal.

11. Corporate Income Tax

11.1 Summary

Chapter 9 of ElectraNet's Revenue Proposal (May 2012) presented ElectraNet's proposed allowance for corporate income tax for the 2013-2018 regulatory control period.

In its Draft Decision, the AER:

- did not accept ElectraNet's proposed corporate income tax allowance of $30.7 million ($nominal) for the 2013-2018 regulatory control period (page 193);
- accepted ElectraNet's proposed method of establishing the opening Tax Asset Base (TAB) at as 1 July 2013, removed two incorrect adjustments to the opening TAB value, and adjusted the opening TAB to reflect the AER's adjustments to actual capex values in the RFM, increasing the opening TAB by a net $2.0 million to $1407.0 million (page 194);
- accepted ElectraNet's proposed standard tax asset lives for the majority of asset classes with the exception of the 'Equity raising cost 2013-2018' and 'Transmission line refit' asset classes, for which tax asset lives were reduced from 43 years to 5 years, and from 47.5 years to 27 years respectively (page 195); and
- accepted ElectraNet's proposed weighted average method to calculate the remaining tax asset lives as at 1 July 2013, and revised the proposed remaining tax asset lives to reflect the AER's adjustments to ElectraNet's actual capex in the RFM (page 195).

ElectraNet has incorporated all aspects of the AER's Draft Decision in relation to the corporate income tax allowance, with the exception of:

- the AER's proposed standard tax asset life for 'Transmission line refit' asset class, which is addressed in Section 11.2 below;
- the AER's assessment of the TAB as at 1 July 2013, which ElectraNet has adjusted as explained in Section 11.3 below; and
- the AER's proposed capital expenditure allowance, which ElectraNet does not accept for the reasons set out in Chapter 6.

This chapter concludes in Section 11.4 by presenting ElectraNet's revised tax allowance, which reflects the AER's Draft Decision and the matters noted above.

11.2 Standard Tax Asset Lives

AER Draft Decision

In its Draft Decision, the AER did not accept ElectraNet's proposed standard tax life of 47.5 years for the 'Transmission line refit' asset class, and substituted a proposed tax life of 27 years.

The AER considered that the standard tax asset life for the 'Transmission line refit' asset class should reflect the life of the asset used for regulatory depreciation purposes. The AER determined a standard asset life for regulatory depreciation purposes of 27 years, calculated based on the weighted average of the economic lives of these assets.

The AER also proposed that the asset class be renamed 'Transmission lines refit-insulators replacement 2013–2018'.[209]

ElectraNet Response

ElectraNet has incorporated in its revised Revenue Proposal a standard tax asset life for the transmission line refit class that is reflective of the standard asset life of this class for regulatory depreciation purposes, which, as discussed in Chapter 10, ElectraNet considers is 15 years.

This is consistent with the AER's Draft Decision that the standard tax asset life for the transmission line refit class should reflect the standard asset life of this class for regulatory depreciation purposes.

Accordingly, ElectraNet has applied a standard economic life for tax purposes of 15 years to the 'Transmission line refit'-insulators replacement 2013-2018' asset class in this revised Revenue Proposal.

For completeness, Table 11-2 sets out the standard tax asset lives adopted for ElectraNet's asset classes.

[209] As noted in Chapter 10, ElectraNet accepts the AER's proposed name change.

Table 11-1 Standard tax asset lives

Asset Class	AER Draft Decision	Revised Revenue Proposal
Commercial Buildings	40.0	40.0
Communication - Civil	12.5	12.5
Communication - Other	12.5	12.5
Computers, Software and Office Machines	3.3	3.3
Easements	n/a	n/a
Land	n/a	n/a
Network Switching Centres (e.g. SCADA)	4.0	4.0
Office Furniture, Movable Plant and Miscellaneous	12.8	12.8
Refurbishment 2003-2008[210]	43.8	43.8
Substation Primary Plant	40.0	40.0
Substation Demountable Buildings	40.0	40.0
Substation Establishment	40.0	40.0
Substation Fences	40.0	40.0
Substation Secondary Systems - Electromechanical	12.5	12.5
Substation Secondary Systems - Electronic	12.5	12.5
Transmission Lines - Overhead[211]	47.5	47.5
Transmission Lines - Underground	47.5	47.5
Working Capital	n/a	n/a
Accelerated Depreciation	5.0	5.0
Refurbishment Projects 2008-2013	40.0	40.0
Equity raising cost - 2003 opening RAB and 2003-2008 capex	43.0	43.0
Equity raising cost 2013-2018	5.0	5.0
Transmission Lines Refit - Insulators Replacement 2013-2018[212]	27.0	15.0

11.3 Revised Tax Asset Base

ElectraNet's revised opening TAB as at 1 July 2013 is $1,352.8 million compared with $1,407.0 million included in the AER's Draft Decision. The difference in opening TAB is due to:

- re-inclusion of capex provisions in the RFM of $3.2 million for the reasons outlined in Chapter 9;
- use of actual 2011-12 capital expenditure which was not available at the time the Revenue Proposal was submitted; and
- update of forecast capital expenditure for 2012-13.

210 Refurbishment projects for the 2003-8 regulatory control period.
211 Value contained in the Draft Decision RFM approved by the AER.
212 The AER changed the name of this asset class from 'Transmission line refit'.

ElectraNet notes that the AER will update the roll forward of the opening TAB with actual March 2013 CPI in publishing its Final Decision.

Table 11-2 shows the revised opening TAB at 1 July 2013.

Table 11-2 Revised opening TAB at 1 July 2013 ($m nominal)

	2008-09	2009-10	2010-11	2011-12	2012-13
Opening TAB	874.4	902.7	891.0	948.5	1,213.3
Capital Expenditure as commissioned	56.7	19.5	90.6	302.5	187.3
Tax depreciation	(28.4)	(31.3)	(33.0)	(37.8)	(47.9)
Closing TAB	**902.7**	**891.0**	**948.5**	**1,213.3**	**1,352.8**

The reduction in the Tax Asset Base relative to the Draft Decision largely reflects a reduction in commissioned asset values in years 2011-12 and 2012-13 relative to the forecast as at May 2012.

11.4 Revised Taxation Allowance

In accordance with the accepted weighted average method, ElectraNet has updated its remaining tax asset lives as at 1 July 2013 to reflect its updated actual capex included in the roll forward of the RAB in the RFM, as discussed in Chapter 9.

Table 11-3 sets out the remaining tax asset lives associated with ElectraNet's asset classes.

Table 11-3 Remaining tax asset lives as at 1 July 2013

Asset Class	AER Draft Decision	Revised Revenue Proposal
Commercial Buildings	32.1	30.9
Communication - Civil	36.8	38.0
Communication - Other	10.9	10.7
Computers, Software and Office Machines	2.8	2.8
Easements	n/a	n/a
Land	n/a	n/a
Network Switching Centres (e.g. SCADA)	4.0	n/a
Office Furniture, Movable Plant and Miscellaneous	11.9	11.8
Refurbishment 2003-2008	31.3	31.3
Substation Primary Plant	33.1	32.9
Substation Demountable Buildings	39.4	39.4
Substation Establishment	38.4	38.7
Substation Fences	40.0	40.0
Substation Secondary Systems - Electromechanical	18.4	18.4
Substation Secondary Systems - Electronic	11.9	11.6
Transmission Lines - Overhead	27.6	26.4
Transmission Lines - Underground	44.2	44.1
Working Capital	n/a	n/a
Accelerated Depreciation	n/a	n/a
Refurbishment Projects 2008-2013	40.0	40.0
Equity raising cost - 2003 opening RAB and 2003-2008 capex	38.0	38.0
Equity raising cost 2013-2018	n/a	n/a
Transmission Lines Refit - Insulators Replacement 2013-2018[213]	n/a	n/a

ElectraNet's revised taxation allowance for the next regulatory control period is shown in Table 11-4. This tax allowance has been calculated using the PTRM and the tax depreciation which incorporates all aspects of the AER's Draft Decision, with the exception of:

- The standard tax life for the 'Transmission line refit' asset class (ElectraNet has included in the revised proposal a standard tax life for this asset class of 15 years); and
- Remaining tax asset lives (updated as above).

Table 11-4 Revised tax allowance ($m, nominal)

	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Corporate income tax	14.2	15.5	16.4	18.0	15.9	80.3
Less value of imputation credits	(9.4)	(10.0)	(10.7)	(11.7)	(10.4)	(52.2)
Tax allowance	5.1	5.4	5.7	6.3	5.6	28.1

Table 11-5 compares the revised tax allowance with the AER's Draft Decision. Differences in the tax allowance also include the consequential impacts discussed in other relevant chapters, such as the revised capital expenditure forecast.

Table 11-5 Revised tax allowance comparison ($m, nominal)

	2013-14	2014-15	2015-16	2016-17	2017-18	Total
AER Draft Decision	4.8	5.1	5.4	6.2	5.2	**26.8**
Revised Revenue Proposal	5.1	5.4	5.7	6.3	5.6	**28.1**

12. Maximum Allowed Revenue

12.1 Summary

This chapter sets out ElectraNet's calculation of the Maximum Allowable Revenue (MAR) for each year of the 2013-2018 regulatory control period. The revenue building-block components include in ElectraNet's Revenue Proposal (May 2012) have been updated in line with the matters set out in this revised Revenue Proposal.

The building block formula to be applied in each year of the revenue control period is:

MAR	=	return on capital + return of capital + Opex + Tax
	=	(WACC x RAB) + D + Opex + Tax

where:

MAR	=	Maximum allowable revenue
WACC	=	post tax nominal weighted average cost of capital ('vanilla' WACC)
RAB	=	Regulatory Asset Base
D	=	economic depreciation (nominal depreciation – indexation of the RAB)
Opex	=	operating expenditure + EBSS payments
Tax	=	regulated business corporate tax allowance

This revenue is then smoothed by an X factor in accordance with the requirements of clause 6A.6.8 of the Rules. A brief summary of each of the building blocks, the unsmoothed revenue and smoothed revenue is outlined in the following sections.[214]

12.2 Regulatory asset base

The movements in the regulatory asset base over the 2013-14 to 2017-18 regulatory period are set out in Table 12-1. These movements reflect the capital expenditure forecast set out in Chapter 6 and the revised depreciation forecast over the period as set out in Chapter 10 of this revised Revenue Proposal.

Table 12-1 Asset Base Roll-Forward from 1 July 2013 to 30 June 2018 ($m nominal)

Regulatory Asset Base	2013-14	2014-15	2015-16	2016-17	2017-18
Opening RAB	2,087.3	2,282.6	2,412.8	2,552.8	2,660.9
Net capex	224.7	165.4	187.6	162.9	86.9
Straight line depreciation	(81.7)	(92.2)	(107.9)	(118.7)	(123.4)
Inflation adjustment on RAB	52.2	57.1	60.3	63.8	66.5
Closing RAB	2,282.6	2,412.8	2,552.8	2,660.9	2,690.9

214 The figures presented in this chapter are expressed in end of year ($June) terms, consistent with the outputs of the PTRM.

12.3 Return on capital

The WACC calculation is detailed in Chapter 8 of this revised Revenue Proposal. The return on capital has been calculated by applying the post-tax nominal vanilla WACC[215] to the opening regulatory asset base consistent with the AER post tax revenue model. This calculation is shown in Table 12-2 below:

Table 12-2 Return on Capital from 1 July 2013 to 30 June 2018 ($m nominal)

Return on Capital	2013-14	2014-15	2015-16	2016-17	2017-18
Opening RAB	2,087.3	2,282.6	2,412.8	2,552.8	2,660.9
Return on capital	148.5	162.4	171.6	181.6	189.3

12.4 Depreciation

The calculation of depreciation is detailed in Chapter 10 of this revised Revenue Proposal. The AER's post tax revenue model calculates economic depreciation by subtracting the indexation of the opening asset base from the depreciation for each regulatory year. A summary of this calculation is shown in Table 12-3 and Table 12-4 below.

Table 12-3 Regulatory Depreciation from 1 July 2013 to 30 June 2018 ($m nominal)

Depreciation	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Straight line depreciation	81.7	92.2	107.9	118.7	123.4	**523.9**
Inflation adjustment on RAB	(52.2)	(57.1)	(60.3)	(63.8)	(66.5)	**(299.9)**
Regulatory depreciation	29.5	35.1	47.6	54.9	56.8	**224.0**

Table 12-4 Tax Depreciation from 1 July 2013 to 30 June 2018 ($m nominal)

Depreciation	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Tax depreciation	55.1	64.1	78.1	85.3	96.9	**379.4**

12.5 Operating expenditure

The calculation of operating expenditure (opex) is detailed in Chapter 7 of this revised Revenue Proposal. The total opex including efficiency benefit sharing scheme, is shown in Table 12-5 below.

215 As noted in Chapter 8, the WACC used for the purposes of this revised Revenue Proposal is based on an indicative averaging period for the risk-free rate and debt risk premium as adopted in the Draft Decision, and will be updated in the AER's Final Decision.

Table 12-5 Operating expenditure from 1 July 2013 to 30 June 2018 ($m Nominal)

Operating Expenditure	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Controllable opex	81.5	88.9	91.3	92.8	94.9	449.4
Self insurance	1.3	1.4	1.5	1.6	1.6	7.4
Network support costs	8.4	8.7	9.0	9.5	9.8	45.4
EBSS	(0.6)	(2.5)	(1.9)	0.0	4.4	(0.6)
Debt raising costs	1.2	1.3	1.3	1.4	1.5	6.6
Total	**91.9**	**97.7**	**101.2**	**105.2**	**112.3**	**508.3**

12.6 Tax allowance

The calculation of the corporate tax allowance is detailed in Chapter 11 of this revised Revenue Proposal. The corporate tax allowance is shown in Table 12-6 below:

Table 12-6 Tax allowance from 1 July 2013 to 30 June 2018 ($m nominal)

Tax Allowance	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Tax payable	14.5	15.5	16.4	18.0	15.9	**80.3**
Less value of imputation credits	(9.4)	(10.0)	(10.7)	(11.7)	(10.4)	**(52.2)**
Net tax allowance	5.1	5.4	5.7	6.3	5.6	**28.1**

12.7 Revised Maximum Allowed Revenue

The unsmoothed revenue requirement for each year of the period is calculated as the sum of return on capital, return of capital, operating expenditure, efficiency carry-over and corporate tax allowance. The outcomes are presented in Table 12-7 below:

Table 12-7 Unsmoothed revenue requirement 1 July 2013 to 30 June 2018 ($m nominal)

Unsmoothed Revenue	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Return on capital	148.5	162.4	171.6	181.6	189.3	853.4
Return of capital	29.5	35.1	47.6	54.9	56.8	224.0
Operating expenses	92.4	100.3	103.1	105.2	107.9	508.9
Efficiency carry over	(0.6)	(2.5)	(1.9)	0.0	4.4	(0.6)
Net tax allowance	5.1	5.4	5.7	6.3	5.6	28.1
Unsmoothed revenue requirement	274.9	300.6	326.2	348.1	364.0	1,613.8

12.8 Revised smoothed revenue

ElectraNet has incorporated in this revised Revenue Proposal the methodology used by the AER in its Draft Decision for the smoothing of the MAR.

Clause 6A.6.8 of the Rules requires the MAR to be equal to the NPV of the annual building block revenue requirement, while ensuring the expected MAR for the last regulatory year is as close as reasonably possible to the annual building block revenue requirement.

Under the approach applied by the AER, in order to achieve a smooth average price transition between the current and forthcoming regulatory periods, the smoothed revenue for the final year 2017-18 is permitted to vary within a 3 per cent tolerance margin of the unsmoothed annual building-block revenue requirement in the 2017-18 year.[216]

Consistent with this approach, the proposed X factors are presented in Table 12-8 below.

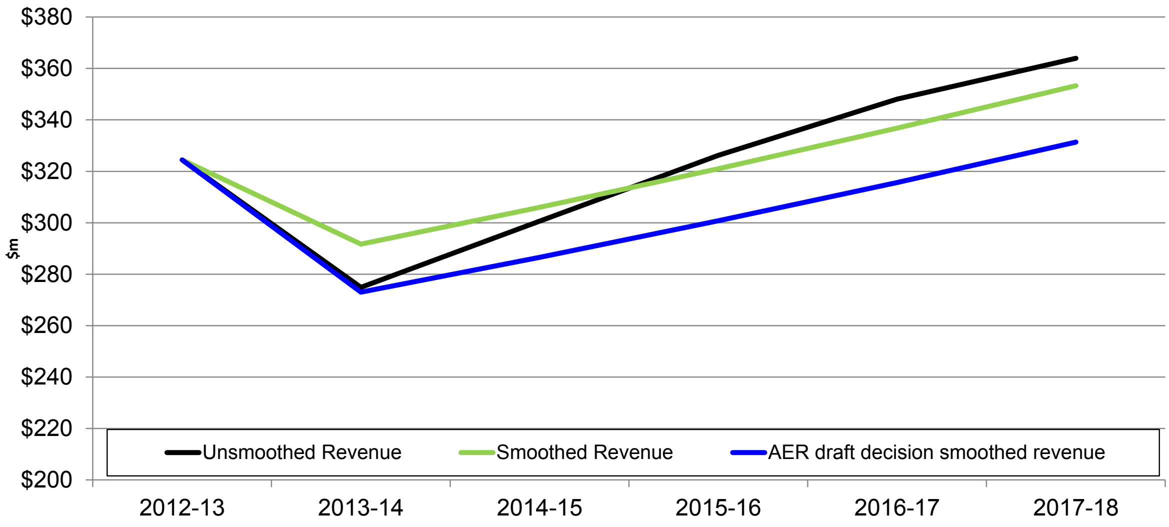
Table 12-8 Smoothed revenue requirement, 1 July 2013 to 30 June 2018 ($m nominal)

	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Unsmoothed revenue requirement	324.5	274.9	300.6	326.2	348.1	364.0	1,613.8
Smoothed revenue requirement	324.5	291.7	306.0	321.0	336.8	353.3	1,608.8
X factor	-	n/a	(2.4%)	(2.4%)	(2.4%)	(2.4%)	-
AER Draft Decision smoothed revenue requirement	324.5	273.0	286.5	300.8	315.7	331.3	1507.3
AER Draft Decision X factor	-	n/a	(2.4%)	(2.4%)	(2.4%)	(2.4%)	-

Figure 12-1 shows ElectraNet's smoothed revenue path in nominal terms compared with the AER's Draft Decision.

216 AER, Draft Decision, page 204.

Figure 12-1 Revenue path ($m nominal)



12.9 Revised average price path

ElectraNet determines its transmission charges based on the AER's approved revenues and the pricing principles contained in the Rules, and ElectraNet's approved pricing methodology which gives effect to these pricing principles.

The effect of ElectraNet's revised Revenue Proposal on average transmission charges can be estimated by taking the maximum allowed revenues and dividing them by forecast energy delivered in South Australia. Based on this approach, ElectraNet estimates that its Revenue Proposal will result in an average increase of about 0.8 per cent per annum (nominal) in transmission charges from the end of the current regulatory period.[217]

Table 12-9 shows the average price path resulting from this revised Revenue Proposal during the next regulatory period compared with the average price for the final year of the current regulatory period (2012-13). Average transmission charges are estimated to decrease from around $24.9 per MWh in 2012-13 to $22.9 per MWh in 2017-18. This equates to an annual real decrease of 1.7 per cent on average across this period, including an initial reduction of 13.6 per cent in 2013-14.

This results in a customer pricing outcome [in line with / less than] CPI movements and reflects ElectraNet's continuing focus on minimising expenditure increases to the maximum extent possible to enable the business to efficiently operate and maintain the South Australian transmission network.

ElectraNet estimates that the (nominal) average increase in transmission charges described above will add approximately $2.21 to the average residential customer's annual bill of $1,481 (0.15 per cent).[218]

217 Forecast energy figures are medium growth figures taken from AEMO's 2012 National Forecasts.

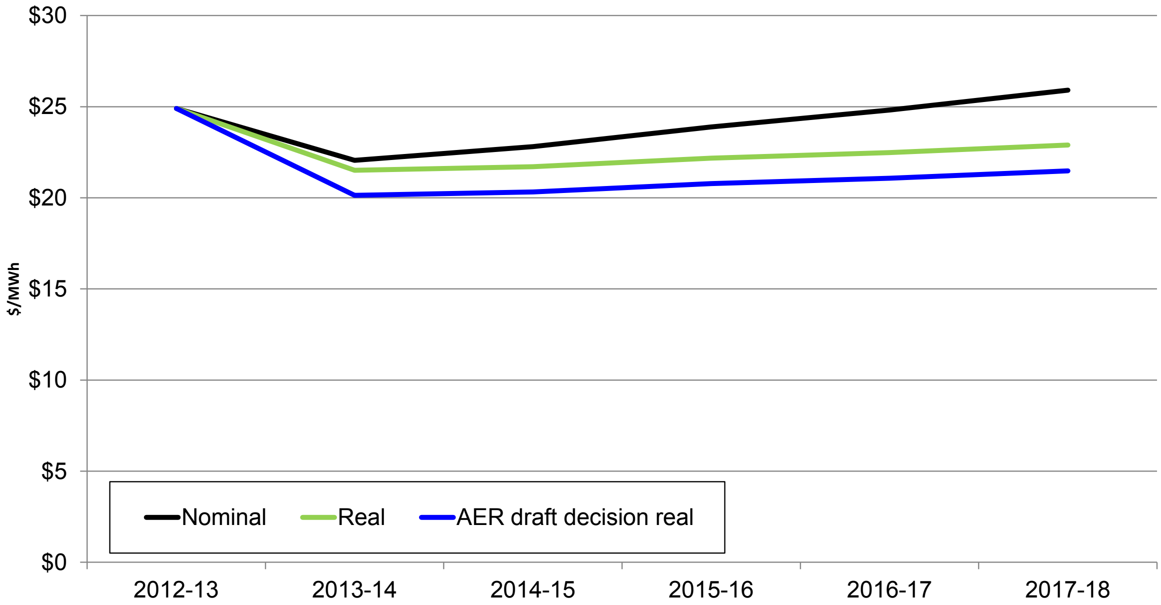
218 Customer billing data from ESCOSA, *Electricity Annual Performance Report - SA Energy Supply Industry*, November 2012, Statistical Appendix 120410.

Table 12-9 Average price path ($m nominal)

	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
Smoothed revenue requirement	324.5	291.7	306.0	321.0	336.8	353.3
Energy (GWh)	13.0	13.2	13.4	13.4	13.6	13.6
Average transmission price ($/MWh, nominal)	24.9	22.1	22.8	23.9	24.8	25.9
Average transmission price ($/MWh, real)	24.9	21.5	21.7	22.2	22.5	22.9
AER Draft Decision transmission price ($/MWh, real)	24.9	20.1	20.3	20.8	21.1	21.5

Figure 12-2 shows the revised Revenue Proposal nominal and real price paths compared with the AER Draft Decision indicative nominal price path.

Figure 12-2 Average price path – nominal and real ($/MWh)



13. Service Target Performance Incentive Scheme

13.1 Summary

Chapter 10 of ElectraNet's Revenue Proposal (May 2012) sets out the performance targets, caps, collars and weightings for each of the parameters for the Service Target Performance Incentive Scheme (STPIS). The structure of the STPIS has both a service component and a market impact component.

In its Revenue Proposal, ElectraNet submitted STPIS parameter values that were not calculated from the data annually reviewed by the AER, but reflected more recent information. As requested by the AER, ElectraNet subsequently resubmitted its STPIS parameter values calculated from the data annually reviewed by the AER.[219]

With respect to the service component, the AER in its Draft Decision:

- approved ElectraNet's proposed revenue weightings for all sub-parameters other than:
  - the Average Outage Duration parameter, for which ElectraNet proposed a weighting of 0.3 per cent and the AER substituted a weighting of 0.2 per cent (page 217);
  - the Loss of Supply Event > 0.05 System Minutes sub-parameter, for which ElectraNet proposed a weighting of 0.1 per cent and the AER substituted a weighting of 0.2 per cent (page 218);
- did not approve ElectraNet's proposal to adjust the availability target parameters for an increase in the volume of capital works (page 218);
- did not approve ElectraNet's proposal to exclude outages associated with any contingent projects triggered during the 2013-2018 regulatory control period (page 219);
- approved ElectraNet's proposed cap and collar values, noting that while the AER did not accept ElectraNet's method of calculating caps and collars, the calculation of caps and collars in accordance with the AER's preferred method did not result in materially different values (page 219);
- did not approve the performance targets calculated by ElectraNet for the three Transmission Circuit Availability sub-parameters, namely Transmission Circuit Availability, Critical Circuit Availability Peak and Critical Circuit Availability Non-Peak, and substituted performance targets for these sub-parameters (Table 11.1, page 209); and
- approved the performance targets calculated by ElectraNet for the remaining parameters, namely the Loss of Supply Events > 0.05 Minutes sub-parameter, the Loss of Supply Events > 0.2 System Minutes sub-parameter, and the Average Outage Duration parameter (Table 11.1, page 209).

219 ElectraNet, *Response to information request AER RP 027*, ENET253, 6 September 2012.

With respect to the market impact parameter, the AER in its Draft Decision:

- did not approve ElectraNet's proposed market impact component STPIS parameter value of 1,588 dispatch intervals, and substituted a performance target of 1,585 dispatch intervals (page 209).

ElectraNet has incorporated all aspects of the AER's Draft Decision in relation to the STPIS in its revised Revenue Proposal, with the exception of the weightings substituted by the AER for the Average Outage Duration parameter and the Loss of Supply Event Frequency - Events > 0.05 system minutes sub-parameter. This matter is addressed in Section 13.2 below. ElectraNet's revised proposed STPIS is presented in Section 13.3.

13.2 Weightings for service component parameters

AER Draft Decision

In its Draft Decision, the AER:

- approved the proposed weightings for all transmission circuit availability sub-parameters, including the proposed reduction in the weighting of the Critical Circuit Availability Peak parameter from 0.2 to 0.1 per cent;
- did not approve ElectraNet's proposed increase in the weighting of the Average Outage Duration parameter from 0.2 to 0.3 per cent, on the basis that ElectraNet had not demonstrated how the increased weighting is consistent with the objectives of the STPIS; and
- did not approve the proposed weighting of 0.1 per cent for the Loss of Supply Event Frequency – Events > 0.05 System Minutes sub-parameter and substituted a value of 0.2 per cent, on the basis that an equal weighting should apply to the two loss of supply sub-parameters.

ElectraNet Response

ElectraNet has not implemented the alternative weightings proposed by the AER in the Draft Decision for the Average Outage Duration parameter and the Loss of Supply Event Frequency - Events > 0.05 system minutes sub-parameter in its revised Revenue Proposal.

Clause 1.4 of the STPIS guideline sets out the objectives of the STPIS. Of particular note in the context of ElectraNet's proposal to increase the weighting of the Average Outage Duration parameter is clause 1.4(d) which requires that the scheme:

> *(d) assists in the setting of efficient capital and operating expenditure allowances in its transmission determinations by balancing the incentive to reduce actual expenditure with the need to maintain and improve reliability for customers and reduce the market impact of transmission congestion.*

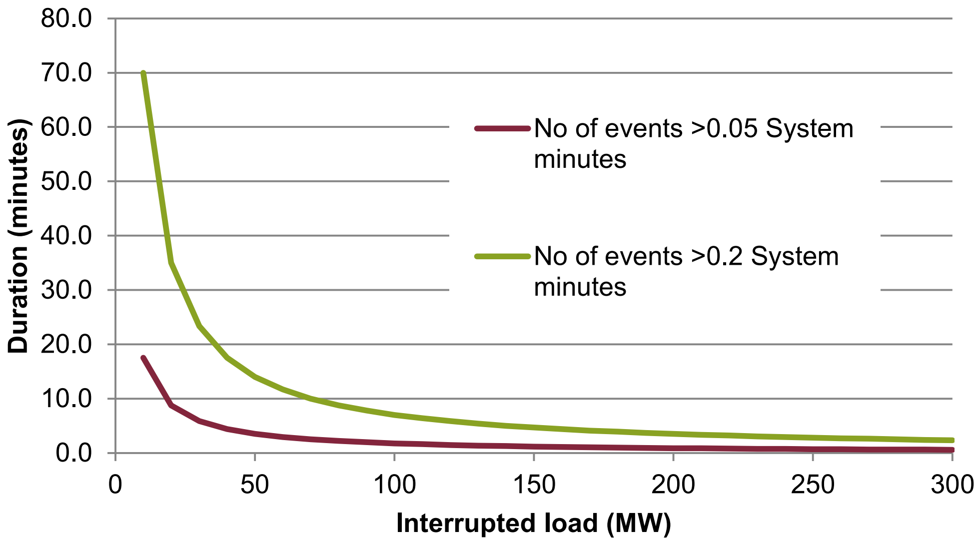
The Loss of Supply Event Frequency sub-parameters and the Average Outage Duration parameter provide complementary incentives to restore supply following customer interruptions.

The Loss of Supply Event Frequency sub-parameters are demand weighted and, as a consequence of the low thresholds that apply to ElectraNet before penalties will start to accrue under the STPIS, very short response times are required in order to avoid these penalties.

Consequently, a 0.05 System Minute event can occur in less than 20 minutes for a 10 MW interruption, while a 0.2 System Minute event for an interruption of this size can occur in approximately 1 hour.

These short durations provide limited opportunities for operational responses by ElectraNet and provide for little meaningful differentiation between the two sub-parameters, as illustrated in Figure 13-1.

Figure 13-1 Loss of supply event sub-parameters



By design, these two measures complement each other, with the longer duration outage sub-parameter (>0.2 system minutes) effectively providing an incremental incentive to the shorter duration outage sub-parameter (>0.05 system minutes).

In practical terms, if ElectraNet incurs a 0.2 System Minute penalty, a 0.05 System Minute penalty will automatically apply as well. Thus by increasing the weighting of the 0.05 System Minute events from 0.1 to 0.2, the penalty associated with 0.2 System Minute events is also significantly increased.

Given the cumulative impact of the two measures operating in tandem, the AER's view that the weightings of both parameters should be aligned has no practical or theoretical merit.

It is also noted that once an outage has exceeded the upper event threshold, these measures provide no further incentive to outage restoration.

In contrast, the Average Outage Duration parameter is neither load weighted nor capped and seeks to measure the average time to restore supply following interruption to supply. As performance against this parameter is typically dominated by long duration outages on the radial network, the parameter provides an extended incentive to reduce the duration of this class of outages.

ElectraNet is concerned that EMCa's advice on the appropriate weightings appears to be based on a view that the STPIS should be designed to minimise the prospect of incentive payments, rather than maximise outage performance. In particular, the AER explains EMCa's advice in the following terms:

> *"The AER's consultant, EMCa, noted that ElectraNet's poor historic performance against the 'average outage duration' parameter was caused by a number of low probability, high impact events. Therefore, a strong probability exists that ElectraNet's 'average outage duration' performance will improve in the 2013–18 regulatory control period with no additional effort from ElectraNet. In such circumstances, EMCa also considered that it was inappropriate to increase the weighting and noted that it was unable to find evidence of any capex or opex proposals directly related to improving performance on the radial network."*[220]

However, it must be remembered that the purpose of the STPIS is to encourage improvements in service performance in accordance with the National Electricity Objective. EMCa's advice appears to be predicated on a view that the STPIS is poorly designed if the company is likely to achieve a bonus. On the contrary, ElectraNet's view is that incentive regulation will only prove effective if performance targets and bonuses are regarded as attainable.

Furthermore, EMCa has employed flawed reasoning in suggesting that the increased weighting should be disallowed because ElectraNet has no specific expenditure proposals to improve performance on the radial network. Performance improvements can be achieved within existing allowances, and result from improved processes and heightened management oversight.

Given the need for a balanced set of measures, ElectraNet considers that appropriate incentives are provided by the Event Frequency sub-parameters and the Average Outage Duration parameter being evenly weighted (each totalling 0.3 per cent) and proposes these revised weightings in Table 13-1.

This approach will further the achievement of the National Electricity Objective, whereas the proposed weightings in the Draft Decision (which would apply twice the incentive to the Event Frequency parameter compared with 'Average Outage Duration' parameter) will not. As already noted, the primary deficiency in the proposed weightings in the Draft Decision is that these are unlikely to encourage an operational response in certain circumstances, and therefore overall the scheme will produce weaker practical incentives to improve service performance.

Table 13-1 Revised proposed weightings for service component parameters

Sub-parameter weightings	Current scheme (%MAR)	Proposed scheme (%MAR)
LOS Events > x System Minutes	0.1	0.1
Average Outage Duration	0.2	0.3

[220] AER, Draft Decision, page 217.

13.3 Revised Service Target Performance Incentive Scheme

ElectraNet's revised proposed parameters and weightings for the purposes of the STPIS for the forthcoming regulatory control period are set out in Table 13-2 below.

Table 13-2 Proposed parameters and weightings

Parameter	Sub Parameter	Performance target	Cap (upper limit)	Collar (lower limit)	Weighting (%MAR)
Transmission Circuit Availability	Transmission Circuit Availability (%)	99.52	99.68	99.02	0.3
	Critical Circuit Availability Peak (%)	99.12	99.96	97.36	0.1
	Critical Circuit Availability Non-Peak (%)	99.37	99.87	98.25	0.0
Loss of Supply Event Frequency	Events > x System Minutes	7.0	4.0	9.0	0.1
	Events > y System Minutes	2.0	0.0	4.0	0.2
Average Outage	Duration (minutes)	203.2	83.2	323.2	0.3
Market impact component	Market impact	1585	0.0	-	2.0

For completeness, these values incorporate all aspects of the AER's Draft Decision with respect to parameters and weightings, with the exception of revised proposed weightings for:

- Loss of supply event frequency - Events > 0.05 system minutes
- Average outage duration

14. Efficiency Benefit Sharing Scheme

14.1 Summary

Chapter 11 of ElectraNet's Revenue Proposal (May 2012) presented ElectraNet's proposed carry-over amount under the Efficiency Benefit Sharing Scheme (EBSS) for the current regulatory control period, and described the proposed application of the EBSS in the forthcoming regulatory control period.

With respect to the application of the EBSS to the current regulatory control period (2008-2013) the AER in its Draft Decision:

- implicitly approved all exclusions proposed by ElectraNet, namely debt raising costs, network support costs and self-insurance costs (page 228);
- explicitly applied further exclusions for movements in provisions and land tax (page 228);
- determined that no adjustments will be made to operating expenditure for actual demand outcomes (page 230);
- did not approve the use of the fourth year (2011-12) for deriving the opex forecast and applied the third year (2010-11) as the base year (page 230);
- did not accept ElectraNet's estimated opex for the fifth year (2012-13) and applied an imputed value in accordance with the formula used to estimate opex in the fifth year under the distribution EBSS guidelines (page 233); and
- did not approve ElectraNet's proposed carryover amount of -$12.2 million ($2012-13) from the application of the EBSS, and determined that a carryover amount of -$4.5 million ($2012-13) should apply (page 227).

With respect to the application of the EBSS to the next regulatory control period (2013-2018) the AER in its Draft Decision:

- did not approve the demand adjustment mechanism proposed by ElectraNet, and determined that no demand adjustment will be applied (page 235);
- accepted all proposed exclusions, namely debt raising costs, network support costs and self-insurance costs (page 235);
- applied further exclusions for movements in provisions, land tax and additional regulatory reset costs (page 235); and
- proposed the opex values to be used to calculate EBSS carryovers (page 236).

ElectraNet has incorporated some aspects of the AER's Draft Decision in relation to the EBSS in its revised Revenue Proposal, while correcting what it submits are errors in the AER's calculation of the carryover amount. ElectraNet has also updated the historic opex expenditure information for the purposes of current period carryover calculations, and updated the EBSS values for the forthcoming regulatory control period to reflect the revised proposed operating expenditure forecast presented in Chapter 7.

14.2 Efficiency Benefit Sharing Scheme (2008-2013)

AER Draft Decision

In its Draft Decision, the AER did not approve ElectraNet's proposed carryover amount of -$12.2 million ($2012-13) from the application of the EBSS to the current regulatory control period.

One reason given by the AER for not approving ElectraNet's proposed carryover amount was because ElectraNet used the fourth year of the current regulatory control period (2011-12) as the base year for the calculation of the EBSS, while the AER preferred that the third year be used (2010-11) for this calculation. The AER preferred the third year because it considered that 2010-11 costs are closer to trend and period average, suggesting that 2010-11 is "more representative of recurrent costs."[221]

The AER set out its views on the linkage between the choice of base year for the EBSS calculation and the forecasting approach for operating expenditure as follows:[222]

> "The AER used 2010–11 as the base year for its substitute forecast opex rather than the 2011–12 base year proposed by ElectraNet. This is because 2010-11 costs were revealed to be more representative of efficient and recurrent costs.
>
> The AER modelled the impact of the change in the base year, from 2011–12 (as proposed by ElectraNet) to 2010–11. The EBSS penalty is $4.5 million when 2010–11 is used as the base year. The EBSS penalty is $26.9 million when 2011–12 is used. However, the difference between the penalties is almost entirely compensated for by the lower opex forecast driven by the different base year. That is, the EBSS carryover amount cannot be considered independently of total forecast opex. The AER found that the total outcome from changing the base year from 2011–12 to 2010–11 resulted in a relatively small difference between the two scenarios in the 2013–2018 regulatory control period. The AER selected 2010–11 as the base year, because it better represented recurrent costs."

In determining the EBSS carryover for the current regulatory control period, the AER did not approve ElectraNet's estimated opex for the fifth year (2012-13) and applied an imputed value in accordance with the formula used to estimate opex in the fifth year under the distribution EBSS guidelines, as follows:

$$A_{2012\text{-}13} = F_{2012\text{-}13} - (F_b - A_b)$$

where:

$A_{2012\text{-}13}$ is the imputed actual opex for the fifth year (2012-13)

$F_{2012\text{-}13}$ is the forecast (i.e. allowance) opex for the fifth year (2012-13)

F_b is the forecast (i.e. allowance) opex in the base year (2010-11)

A_b is the actual opex in the base year (2010-11)

On this basis, the AER determined a carryover amount of -$4.5 million ($2012-13) from the application of the EBSS to the 2008-2013 regulatory control period.

221 AER, Draft Decision, page 230.
222 AER, Draft Decision, page 41.

The AER indicated it excluded the following cost categories from forecast and actual operating expenditure for the 2008-2013 regulatory control period for the purposes of calculating EBSS carry over payments:

- Debt raising costs
- Network support costs
- Self insurance costs
- Movements in provisions
- Land tax

The Draft Decision only explicitly refers to two exclusions in respect of the 2008-2013 period that are additional to those proposed by ElectraNet – being the exclusion of movements in provisions and land tax.[223] The EBSS calculations supplied by the AER also exclude debt raising costs, network support costs and self-insurance costs, as proposed by ElectraNet, which ElectraNet has interpreted to be an implicit approval of ElectraNet's proposed exclusions. The Draft Decision does not explicitly state that the AER intended to exclude additional regulatory reset costs for the purposes of calculating carry over payments from the 2008-2013 regulatory control period, nor are any adjustments for these amounts included in the EBSS calculations supplied by the AER. For the purposes of the Draft Decision, ElectraNet assumes that the exclusions as listed above have been approved by the AER for the purposes of the 2008-2013 EBSS calculations.

ElectraNet Response

ElectraNet addresses the above matters arising from the Draft Decision in turn.

<u>Selection of the Base year</u>

In its Draft Decision, the AER did not approve the use of 2011-12 (year 4) as representative of efficient or recurrent costs. The AER instead applied 2010-11 (year 3) as the base year for the purposes of deriving the opex forecast, which it considered to be an efficient recurrent base year.

As noted in Chapter 7 (Operating Expenditure), ElectraNet does not agree that the historic costs incurred in 2011-12 are not efficient or representative. However, ElectraNet has incorporated in this revised Revenue Proposal the use of year 3 (2010-11) as the base year for both deriving the operating expenditure allowance (with adjustments for appropriate step changes) and for calculating EBSS carry over payments.

<u>Treatment of Year 5</u>

In discussions with AER staff, ElectraNet noted that the Draft Decision is potentially open to interpretation as to whether the AER intends to adopt and maintain an imputed value for ElectraNet's actual operating expenditure for 2012-13, or to update the EBSS calculations when ElectraNet's actual operating expenditure for 2012-13 is known, given the references in the Draft Decision to an 'estimate' for this year.

In addition, the First Proposed EBSS to which ElectraNet is subject in the current regulatory control period provides for the AER and ElectraNet to agree an approach for addressing differences between forecast and actual operating expenditure in the final year of the scheme.

223 AER, Draft Decision, page 230.

In light of this, ElectraNet took the opportunity to clarify the AER's intended application of the EBSS in its Draft Decision.[224]

In response, the AER confirmed that:[225]

> The (imputed) actual operating expenditure for 2012-13 is determined according to the base year used to forecast controllable opex for the 2008-2013 regulatory control period. Once the carryover amount for the 2008-2013 regulatory control period has been published in the AER's final decision, it then does not require updating for actual opex outcomes in 2012-13.

Accordingly, ElectraNet has applied the formula adopted by the AER to determine the applicable value for opex in year 5 (2012-13) for the purposes of the EBSS carryover calculation.

Exclusions

ElectraNet has not incorporated in this revised Revenue Proposal the revisions in the Draft Decision relating to movements in provisions from forecast and actual operating expenditure for the purposes of the EBSS carry over calculation.

ElectraNet does not accept the removal of movements in provisions as non-controllable expenditure items. Provisions properly constitute efficient base year expenditure for liabilities incurred, and form part of the controllable historic and forecast operating expenditure. Equally, ElectraNet does not accept the removal of provisions from the operational expenditure forecast for these reasons, as presented in Chapter 7.

ElectraNet has therefore not incorporated these adjustments in its EBSS calculations.

Calculation errors

ElectraNet was supplied with the model applied by the AER to determine the EBSS carryover for the purposes of its Draft Decision.[226] ElectraNet has identified what it considers to be a number of errors in the assumptions and inputs to the EBSS calculation as applied by the AER, involving the use of incorrect or superseded data. These include:

- adjustment for superannuation provision movements from 2005-06;
- apportionment of employee leave provisions to operating expenditure; and
- land tax adjustments.

These issues are addressed in turn below.[227] With regard to movements in superannuation and employee leave provisions, as noted above, ElectraNet does not accept the AER's proposed adjustment for movements in provisions.

ElectraNet has provided the information presented below only for the purposes of enabling the AER, if it maintains its view that the movement in these provisions should be excluded from the calculation of the EBSS, to apply its calculations accurately.

[224] Letter from ElectraNet to the AER, dated 17 December 2012.
[225] Letter from the AER to ElectraNet, dated 20 December 2012.
[226] Full supporting information on the adjustments applied by ElectraNet has been separately supplied to the AER by email dated 5 December 2012.
[227] ENET290, Efficiency Benefit Sharing Scheme (EBSS), 24 December 2012.

Superannuation provision movements

In its base year calculation for the EBSS target for the 2008-09 to 2012-13 period, the AER has attributed the whole of the superannuation provisions movement for the year to 30 June 2006 ($5.192 million) to operating expenditure.

However, only one-third of this amount is correctly attributable to expenditure (both capital and operating), while the balance was absorbed into the balance sheet through a restatement of ElectraNet's financial accounts for that year. This reflected a change in the accounting treatment which was required at the time to conform to the requirements of the then new Australian International Financial Reporting Standards (AIFRS).

This left only $1.677 million to be allocated to operating and capital expenditure for that year. A full reconciliation of these amounts to ElectraNet's financial statements has been supplied to the AER.[228]

As noted above, ElectraNet does not accept the removal of movements in provisions as non-controllable expenditure items for the purposes of the EBSS, and has not excluded these amounts in its revised proposed EBSS carry over calculations.

Apportionment of employee leave provisions

In accounting for movements in employee leave provisions for the purposes of its EBSS calculation, the AER has determined the relevant opex portion of these movements by applying the ratio of bottom-up (i.e. 60 per cent) to top-down forecast elements and allowing for non-prescribed expenditure (5 per cent). When combined, this results in a factor of 57 per cent which is assumed to represent the controllable opex component of the provisions in the base year, and the AER has removed the remainder from the operating expenditure target.

However, this methodology is incorrect both in terms of its approach and the numerical calculation. First, the correct allocation of employee leave provision movements is based on apportionment between capital and operating expenditure. Secondly, in terms of the calculation itself, the bottom up forecast components largely relate to outsourced services and contain minimal internal labour cost.

For the relevant year (2005-06), 39.1 per cent of the employee leave provision movement should correctly be allocated to capital expenditure, leaving 60.9 per cent attributable to operating cost. After apportionment to non-prescribed expenditure (4.2 per cent) this represents a total of 58.3 per cent that is correctly attributable to prescribed operating expenditure.

If the AER maintains its view that movements in employee leave provisions should be treated as non-controllable expenditure and removed from opex for the purposes of the calculation of the EBSS, ElectraNet submits that this should be done on the basis of the allocation of the employee leave provision movement to opex and capex and non-prescribed expenditure. This requires the use of an allocation factor of 58.3 per cent (and not 57 per cent).

For completeness, the corrected values for provision movements for the purposes of this calculation are set out in Table 14.1.

[228] ENET290, Efficiency Benefit Sharing Scheme (EBSS), 24 December 2012.

Table 14-1 Corrected adjustment to controllable opex allowance for provisions ($m 2012-13)

	2008-09	2009-10	2010-11	2011-12	2012-13	Total
Adjustment for provision movements	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(4.9)

As noted above, ElectraNet does not accept the removal of movements in provisions as non-controllable expenditure items for the purposes of the EBSS, and has not excluded these amounts in its revised proposed EBSS carry over calculations.

Land tax adjustments

In the absence of historical data, the AER developed an estimate of historic land tax payments based on the ratio of land tax to total direct charges in 2011-12 for the purposes of its Draft Decision EBSS calculations.

ElectraNet has incorporated the exclusion of land tax payments in the calculation of the EBSS. Historical data relating to land tax payments is available and accordingly, ElectraNet has applied actual historical land tax payments in its revised proposed EBSS calculations.

<u>Revised carryover amount</u>

ElectraNet has incorporated the applicable adjustments above, and applied actual opex for 2011-12 and updated forecast controllable opex for 2012-13 for the purposes of its revised proposed EBSS calculations.

In summary, for the purposes of the EBSS carry over calculation for the 2008-2013 regulatory control period, ElectraNet has applied the following methodology:

- The formula adopted by the AER to determine the applicable value for opex in year 5 (2012-13)
- Year 3 (2010-11) as the base year
- Exclusion of the following cost categories from forecast and actual operating expenditure:
    - Debt raising costs
    - Network support costs
    - Self insurance costs
    - Land tax

These revised figures are presented in Table 14-2 below.

Table 14-2 Revised EBSS carryover amounts ($m 2012-13)

	2008-09	2009-10	2010-11	2011-12	2012-13	Total
AER Draft Decision	(3.8)	(3.7)	(1.5)	0.0	4.5	**(4.5)**
Revised Revenue Proposal	(0.6)	(2.4)	(1.7)	0.0	3.9	**(0.8)**

As required, these calculations are presented in the Submission Guidelines pro forma statement 7.4 which accompanies this revised Revenue Proposal.

An adjustment for the above amounts has been included in the PTRM for the forthcoming regulatory control period.

14.3 Efficiency Benefit Sharing Scheme (2013-2018)

AER Draft Decision

In its Draft Decision, the AER approved the following cost categories to be excluded from forecast and actual operating expenditure for the 2013-2018 regulatory control period for the purposes of calculating EBSS carry over payments:[229]

- debt raising costs;
- network support costs;
- self insurance costs;
- movements in provisions;
- land tax; and
- additional regulatory reset costs.

The AER calculated the total controllable opex forecasts that it will use to calculate efficiency gains and losses in the 2013-2018 regulatory control period on the basis of these excluded cost categories and its substituted opex forecast.[230]

ElectraNet Response

ElectraNet has incorporated all aspects of the AER's Draft Decision in relation to ElectraNet's proposed EBSS for the forthcoming regulatory control period, with the exception of the following excluded cost category proposed by the AER:

- Movements in provisions

For the reasons outlined above, ElectraNet does not accept the exclusion of these costs as non-controllable expenditure items from forecast and actual operating expenditure for the purposes of calculating EBSS carry over amounts.

For the purposes of establishing the controllable operating expenditure forecasts applicable to the EBSS calculation for the forthcoming regulatory control period, ElectraNet proposes the controllable opex forecast outlined in Table 14-3, consistent with its revised proposed operating expenditure forecast and the applicable exclusions listed above.

229 Draft Decision, page 235.
230 Draft Decision, page 228.

Table 14-3 Revised EBSS operating expenditure forecasts ($m 2012-13, mid-year)

	2013-14	2014-15	2015-16	2016-17	2017-18	Total
Forecast operating expenditure	88.5	91.9	92.8	94.2	98.0	**465.4**
Adjustment for debt raising costs	(1.1)	(1.2)	(1.2)	(1.3)	(1.3)	**(6.1)**
Adjustment for network support	(8.1)	(8.2)	(8.2)	(8.5)	(8.6)	**(41.6)**
Adjustment for self-insurance	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	**(6.8)**
Adjustment for land tax	(2.1)	(2.2)	(2.3)	(2.5)	(2.7)	**(11.8)**
Adjustment for regulatory reset costs	0.0	0.0	0.0	0.0	0.0	**0.0**
Forecast operating expenditure for EBSS purposes	**75.9**	**79.0**	**79.7**	**80.5**	**84.1**	**399.2**

These forecasts are compared with the Draft Decision values in Table 14.4.

Table 14-4 Comparison of EBSS operating expenditure forecasts ($m 2012-13, mid-year)

	2008-09	2009-10	2010-11	2011-12	2012-13	Total
AER Draft Decision	62.4	65.5	66.2	67.0	67.8	**328.9**
Revised Revenue Proposal	75.9	79.0	79.7	80.5	84.1	**399.2**

15. Contingent Projects

15.1 Summary

A contingent project is a project assessed by the AER as reasonably required to be undertaken, but which is excluded from the ex-ante capital expenditure allowance in a revenue determination because of uncertainty about its requirement, timing or costs.[231] Within the transmission regulatory framework, contingent projects provide an important balance between incentives for investment and efficiency. ElectraNet proposed 21 contingent projects, as outlined in section 5.10 and Appendix Q of its Revenue Proposal (May 2012).

In its Draft Decision, the AER:

- did not accept any of the contingent projects proposed by ElectraNet as meeting the requirements of the Rules (page 241);
- concluded that a total of 6 projects were associated with load growth that had already been taken into account in the development of the ex-ante capex forecast (pages 244, 245);
- determined that a total of 10 contingent projects were not considered probable during the 2013-2018 regulatory control period (page 246);
- considered that the 5 remaining projects might satisfy the requirements of the Rules if the trigger events were suitably modified, and proposed alternative trigger events for these projects (page 250); and
- identified a number of specific issues in relation to the Lower Eyre Peninsula Reinforcement,[232] Riverland Reinforcement and South East to Heywood Interconnection Upgrade proposed contingent projects (pages 250, 251).

The following sections present ElectraNet's response to a number of matters raised in the AER's Draft Decision, including where ElectraNet has not incorporated in its revised Revenue Proposal the revisions specified in the Draft Decision. ElectraNet also provides additional information and analysis where necessary to assist the AER in reaching its Final Decision. Further details on each of the contingent projects are available in Appendix M of this revised Revenue Proposal.

15.2 Contingent projects associated with load growth

AER Draft Decision

In its Draft Decision, the AER concluded that a number of proposed contingent projects address circumstances that have already been taken into account in the development of the ex-ante allowance. Specifically, it considered that 6 projects address demand scenarios already included in the ex-ante allowance, and that to include these as contingent projects would be to allow double recovery of capital expenditure to meet the same demand.

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231 *Process guideline for contingent project applications under the National Electricity Rules*, AER, September 2007.

232 The Lower Eyre Peninsula Reinforcement contingent project was incorrectly referred to as the Lower Eyre Peninsula Connection Point contingent project in the Draft Decision.

On this basis, the AER did not accept 6 proposed contingent projects, categorised as follows:

- Projects associated with general load growth triggered by a demand increase that ElectraNet forecasts will occur in the 2013-2018 regulatory control period:
  - Lower Eyre Peninsula Reinforcement
  - Yorke Peninsula Reinforcement
- Projects triggered by a connection point request which appear to be driven by demand increases that are within ElectraNet's demand forecast for the 2013-2018 regulatory control period:
  - Fleurieu Peninsula Reinforcement
  - Western Suburbs Reinforcement
  - Northern Suburbs Reinforcement
  - Port Pirie System Reinforcement

The AER also expressed concern that using contingent projects to assist in managing cost impacts on consumers potentially removes the incentives for TNSPs to manage their network within the capex allowance under the regulatory framework.

The AER considered that in light of its revised demand forecast some of the proposed contingent projects might now be relevant if a lower demand forecast is applied in the final decision. On this basis it might therefore be necessary for ElectraNet to propose some additional contingent projects in its revised Revenue Proposal. ElectraNet understands this also extends to include projects that were included in the ex-ante forecast in its original proposal.

ElectraNet Response

ElectraNet addresses the above issues in turn.

<u>Demand Scenarios</u>

The AER's consultant, EMCa, found that ElectraNet's forecast load driven capex is sufficient for ElectraNet to meet the reasonably expected growth driven expenditure (that is, it is sufficient to cover natural incremental demand growth provided by the demand scenario envelope -high, medium and low growth).[233] The AER has relied on this finding to *conclude that*

> "…no contingent projects are needed to address the high, medium or low demand scenarios as these are already taken into account in determining the ex-ante allowance."234

In relation to the Eyre Peninsula and Yorke Peninsula reinforcements, the Draft Decision stated that

> "…ElectraNet's forecast capex already provides for these projects."235

[233] EMCa, *Advice on Forecast Capital and Operational Expenditure, Contingent Projects and Performance Scheme Parameters: ElectraNet Revenue Determination – Technical Review*, 30 October 2012, [243], page 78, 79.
[234] AER, Draft Decision, page 243.
[235] AER, Draft Decision, page 244.

These statements are incorrect. The contingent projects identified in ElectraNet's Revenue Proposal were not included in the projects which comprise the ex-ante capital expenditure forecast. The EMCa report in fact notes that ElectraNet has stated that the loads associated with the contingent projects are not included in the demand forecast used as the basis of forecast capex.[236]

Each of the proposed contingent projects were specifically excluded from the probabilistic analysis undertaken to test the sensitivity of that forecast to changes in demand, based on generation and load scenarios developed for ElectraNet by ROAM Consulting.[237] ElectraNet explicitly stated this fact in its Revenue Proposal in noting that:

> "The impact of a probabilistic scenario is somewhat limited by the exclusion of large and uncertain projects from the forecast as contingent projects…"[238]

This demonstrates clearly that the contingent project expenditure is not otherwise provided for in the ex-ante allowance.

However, ElectraNet has reviewed its proposed contingent projects in light of the 10 per cent probability of exceedance demand forecasts on which the load driven capital expenditure program of the revised Revenue Proposal is based. For further explanation of this change in planning standard, see Chapter 4 of this revised Revenue Proposal.

Further advice has been received from SA Power Networks in light of this change on the current likelihood of the contingent projects that would involve the establishment of a new connection point to the distribution network.

This review has revealed that the likelihood of a number of the projects proceeding in the forthcoming regulatory control period has reduced, with a resulting reduction in the number of proposed contingent projects included in this revised Revenue Proposal.

Adoption of the 10 per cent probability of exceedance demand forecasts has deferred the driver date for all load driven contingent projects to beyond the 2013-2018 regulatory control period (other than those driven by a step change in load). For those contingent projects that remain probable during the 2013-2018 regulatory period, ElectraNet has identified the specific step change in load and also the underlying network limitation that this causes.

ElectraNet considers that the revised contingent projects fully address the requirements of the Rules, and respond to all of the specific concerns identified by the AER.

<u>Regulatory Incentives</u>

ElectraNet observes that as a result of the adoption of its revised demand forecast, approximately $130 million of ex-ante load driven capital expenditure has been deferred beyond the 2013-2018 regulatory control period. As a consequence, there is minimal load driven capital expenditure allowance in the years 2015-16 to 2017-18 to absorb the impact of future fluctuations in demand.

236 EMCa, *Advice on Forecast Capital and Operational Expenditure, Contingent Projects and Performance Scheme Parameters: ElectraNet Revenue Determination – Technical Review*, 30 October 2012, [562], page 148.

237 Contrary to the assertions of its consultant (EMCa, *ElectraNet technical review*, page 88, 89) ElectraNet notes that there is no specific requirement under the Rules for a TNSP to adopt a probabilistic capex forecast.

238 ElectraNet Revenue Proposal, May 2012, page 65.

The approval of the revised proposed contingent project list will therefore have no negative impact on the intended incentive properties of the regulatory framework, as there is no further scope for deferral.

As observed by the AER, treating less certain, but high revenue impact projects as contingent projects means that customers are not required to pay unless the project goes ahead, and the interests of the TNSP are also protected.[239]

The approval of the revised proposed contingent projects will balance the objectives of the Rules, and in particular ensure that the efficiency requirements of the national electricity objective are met.

Cost Uncertainty

ElectraNet also notes that a number of the load driven contingent projects contained in the revised Revenue Proposal currently face significant uncertainty in scope (pending a comprehensive assessment of credible options through the RIT-T process) and therefore cost.

Cost uncertainty in itself is a specific criterion under the Rules for assessing whether a project is sufficiently uncertain to warrant treatment as a contingent project.[240]

This criterion is directly applicable to the Lower Eyre Peninsula Reinforcement, Yorke Peninsula Reinforcement and Fleurieu Peninsula Reinforcement contingent projects, and is applicable independent of the timing of these projects.

Additional Contingent Projects

As anticipated in the Draft Decision, the revised demand forecasts have resulted in the deferral of a number of capital projects beyond the 2013-2018 regulatory control period. The adoption of the revised demand forecasts has also, brought about the need for an additional project to be added to the contingent project list, namely the East Terrace transformer project.

The East Terrace transformer project was originally required to be delivered by 2017 in order to address forecast limitations in the Adelaide CBD in accordance with the requirements of the ETC, and is now scheduled to be commissioned in 2025 on the basis of the 10 per cent probability of exceedance demand forecast. A step load increase, such as the publically announced intentions of the State government to electrify all of the main rail corridors in the Adelaide metropolitan region, would bring forward the need for this project. One of the key electrification nodes is situated within the boundaries of the Adelaide CBD, as this is the central node from which all of the rail transit services radiate to suburban destinations.

Summary

In summary, of the projects discussed above, ElectraNet has included the following proposed contingent projects in its revised Revenue Proposal:

- Lower Eyre Peninsula Reinforcement
- Yorke Peninsula Reinforcement

239 AER, Draft Decision, page 239.
240 Rules 6A.8.1(c)(5)(ii).

- Fleurieu Peninsula Reinforcement
- Northern Suburbs Reinforcement
- Port Pirie System Reinforcement
- East Terrace Transformer

The revised triggers associated with the proposed contingent projects are listed in section 15.5.1 below. Further information is provided in the contingent project summaries included in Appendix M.

Further information on individual projects in response to the specific issues raised by the AER is provided in Section 15.5 below.

15.3 Projects not considered probable within the regulatory control period

AER Draft Decision

In its Draft Decision, the AER did not accept a total of 10 proposed contingent projects which it considered were not probable during the 2013-2018 regulatory control period, as follows:

- Four projects were considered to have a demand increase that had not been justified:
  - Southern Suburbs Reinforcement
  - South East Connection Point Reinforcement
  - South East Region Augmentation
  - Lower South East Region Transformer Reinforcement
- Two projects were considered to be attributable to the proposed Olympic Dam mine expansion (now deferred):
  - Upper Eyre Peninsula Reinforcement
  - Northern Transmission Reinforcement – Load
- Three projects were found to be driven by market benefits without an identified underlying driver:
  - Upper South East Generation Expansion
  - Torrens Island Switchyard Development
  - Para – Brinkworth / Bungama Davenport 275 kV Transmission Upgrade
- One project was considered not to be feasible as presented:
  - Eyre Peninsula Connection Point

The AER indicated that it would expect ElectraNet to justify the inclusion of the contingent project by identifying the driver of the project that will make the occurrence of the trigger event probable during the 2013-2018 regulatory control period.

ElectraNet Response

As noted above, ElectraNet has reviewed its proposed contingent projects in light of the change to a 10 per cent probability of exceedance demand forecast and advice from SA Power Networks on the current timing and likelihood of the proposed DNSP connection points.

Based on this review, ElectraNet considers that for the majority of these projects there is not a sufficient likelihood of the projects being required to warrant inclusion as contingent projects. ElectraNet therefore accepts the AER's Draft Decision not to include the majority of these contingent projects.

In relation to the market benefits projects described above, the AER indicated that ElectraNet should be able to justify the inclusion of each contingent project by identifying the trigger for the project that will make it reasonably required.

Accordingly, ElectraNet has retained the Upper South East Generation Expansion project as a contingent project (more accurately retitled the "Upper South East Network Augmentation project"). The focus of this project is on network augmentation driven by probable market benefits, as demonstrated by further constraints analysis and the likelihood of generation development in the vicinity:

- Detailed analysis undertaken during the course of the Heywood Interconnector Upgrade RIT-T assessment process (published in January 2013)[241] has identified emerging thermal limitations in the Tailem Bend to Tungkillo 275 kV corridor, the extent of which is subject to demand and generation development in the South East and Eastern Hills regions of South Australia;
- Recent announcements by the proponent of a proposed generation development in this vicinity (namely the Cherokee Power Station project)[242] provide a clearer indication of the expected timing of generation development in the region.

In summary, of the projects discussed above, ElectraNet has included the following proposed contingent project in its revised Revenue Proposal:

- Upper South East Network Augmentation

The revised triggers associated with this proposed contingent project are listed in Section 15.5.1 below, and are consistent with those applied by the AER to the South East to Heywood Interconnection Upgrade contingent project, with the addition of the publication by AEMO of evidence of material constraints in this vicinity of the network. Further information is provided in the contingent project summaries included in Appendix M.

241 South Australia – Victoria (Heywood) Interconnector Upgrade, RIT-T Project Assessment Conclusions Report, January 2013.

242 Reports indicate construction has been rescheduled for 2014, with the first stage of the project involving 250MW of capacity scheduled to be commissioned in 2016. Refer: Elemental Power Industries, 26 November 2012, http://elementalpower.com.au/news/?tag=investec.

15.4 Projects the AER considers might satisfy the Rules requirements

AER Draft Decision

The AER found that five of ElectraNet's proposed contingent projects might satisfy the requirements of the Rules, with revisions to the trigger events. The Draft Decision indicates that the AER is satisfied these projects are uncertain and considers that ElectraNet has explained why these projects are reasonably required, with specific reference to the underlying driver of each project. The projects are as follows:

- Davenport Reactive Support
- Mid North Connection Point
- Upper North Region Line Reinforcement
- Riverland Reinforcement
- South East to Heywood Interconnection Upgrade

The AER considered that the trigger events for these projects had not been adequately defined to fully satisfy the requirements of the Rules, and proposed alternative trigger events.

ElectraNet Response

ElectraNet has reviewed the trigger events proposed by the AER, and broadly accepts the intent of the changes proposed. ElectraNet has incorporated the aspect of the Draft Decision which required the trigger events to include a determination by the AER under clause 5.16.6 that the proposed investment satisfies the regulatory investment test for transmission. This is only relevant to investments where the preferred option is not for reliability corrective action (being the South East to Heywood Interconnection Upgrade and Upper South East Network Augmentation).

ElectraNet proposes some minor modifications in a number of instances in the interests of ensuring that the triggers will be practically implementable. These include combining the requirement for a comprehensive assessment of all alternatives with the requirement for the Regulatory Investment Test for Transmission (RIT-T) to be undertaken (which by definition includes a comprehensive assessment of credible options) and other clarifying amendments.

The AER has also proposed in each instance a trigger event requiring:

> "ElectraNet Board commitment to proceed with the project subject to AER approval of the contingent project."

Consistent with the intent of this trigger event, ElectraNet has revised this proposed trigger event as follows:

> *"ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules."*

The purpose of this amendment is to more accurately reflect the requirements of the Rules. Pursuant to clause 6A.8.2, the relevant action of the AER at the time of a contingent project application is, if satisfied that the trigger event has occurred, to amend the revenue determination accordingly, whereas the AER approves contingent projects under the Rules at the time of a transmission determination.

In addition, with respect to the proposed Mid North Connection Point contingent project, SA Power Networks has confirmed that the specific underlying distribution network limitation is the overload of the Bungama to Gladstone 33 kV sub-transmission line (rather than the overload of the Jamestown to Peterborough 33 kV sub transmission line, as proposed in the Draft Decision). The trigger event has been amended accordingly to capture this limitation.

Finally, ElectraNet has amended the primary trigger event for the Davenport Reactive Support contingent project to require the temporary or permanent closure of the Playford and Northern Power Stations. This change in trigger events is based on information that is now available regarding the reactive power requirements of the region following the completion of more detailed reactive planning studies.

In summary, ElectraNet has included each of the proposed contingent projects discussed above in its revised Revenue Proposal, as follows:

- Davenport Reactive Support
- Mid North Connection Point
- Upper North Region Line Reinforcement
- Riverland Reinforcement
- South East to Heywood Interconnection Upgrade

The revised triggers associated with these revised proposed contingent projects are listed in Section 15.5.1 below. Further information is provided in the contingent project summaries included in Appendix M.

15.5 Other Issues

AER Draft Decision

The AER in its Draft Decision identified a number of discrete issues in relation to specific projects:

- Lower Eyre Peninsula - the AER expressed concern that ElectraNet had not substantiated how a relatively small demand increase could trigger the contingent project as proposed;
- Riverland Reinforcement - the AER has proposed alternative trigger events for this project, and indicated that it does not accept the trigger relating to a demand increase, as ElectraNet has not identified the underlying driver; and
- South Australia to Victoria (Heywood) Interconnector Upgrade - while the AER accepts the need in principle for this contingent project, it does not consider that the completion of the RIT-T in itself is a sufficient trigger event. The AER has proposed additional trigger events to address this concern.

ElectraNet Response

The following comments respond to the discrete issues identified by the AER in relation to these specific projects.

Lower Eyre Peninsula

ElectraNet has revised the trigger event for this project to identify the specific step load event that would bring forward the need for this major line augmentation project.

ElectraNet also confirms that the RIT-T assessment for this augmentation has advanced, and a Project Assessment Draft Report was published in January 2013[243] providing full details on the nature of the mining load developments driving this project, and potential solutions being investigated.

Accordingly, ElectraNet has also revised the cost of this project to align with the current estimate of the minimum necessary augmentation anticipated to be necessary. The final solution will be confirmed once the evaluation of credible options is concluded through the current RIT-T process.

Riverland Reinforcement

ElectraNet considers that the probability of a demand based trigger has now diminished in the light of the revised demand forecasts. Accordingly, it has removed this limb of the first trigger for this project, and has retained the remaining limb relating to the available capacity of Murraylink.

South Australia to Victoria (Heywood) Interconnector Upgrade

ElectraNet submits that the need to retain the South Australia to Victoria (Heywood) Interconnector Upgrade as a contingent project is beyond doubt, noting that the RIT-T process is nearing conclusion with the publication of a Project Assessment Conclusions Report in January 2013.[244] ElectraNet has revised its revised Revenue Proposal to incorporate the additional trigger events proposed in the AER's Draft Decision (and has re-ordered these for completeness).

15.5.1 Revised Proposed Contingent Projects

A summary of ElectraNet's revised proposed contingent projects, trigger events and indicative costs is provided in Table 15-1, incorporating revisions to address the issues raised by the AER and fully satisfy the requirements of the Rules, as discussed above. Further information is contained in Appendix M to this revised Revenue Proposal.

[243] *Lower Eyre Peninsula Reinforcement RIT-T Project Assessment Draft Report*, January 2013, ElectraNet, http://www.electranet.com.au/network/current-planned-developments/eyre-peninsula/new-developmentpage-8/rcview/.

[244] *South Australia - Victoria (Heywood) Interconnector Upgrade RIT-T: Project Assessment Conclusions Report*, January 2013, AEMO & ElectraNet, http://www.electranet.com.au/assets/Uploads/Heywood-PACR.pdf.

Table 15-1 Revised proposed contingent projects

Project Name	Trigger	Indicative Cost ($m Nominal)
Lower Eyre Peninsula Reinforcement	1. Customer commitment to a step load increase exceeding 50 MW on the transmission network south of Cultana substation, causing the Cultana to Yadnarie 132 kV transmission line to exceed its thermal limit (73 MVA) 2. Successful completion of the regulatory investment test for transmission including a comprehensive assessment of credible options showing a transmission investment is justified 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	340
Yorke Peninsula Reinforcement	1. Customer commitment to a step load increase exceeding 60 MW on the transmission network south of Ardrossan West substation, causing the Bungama to Snowtown to Hummocks 132 kV transmission line to exceed its thermal limit (105 MVA) on loss of the Waterloo to Hummocks 132 kV transmission line (and vice versa) 2. Successful completion of the regulatory investment test for transmission including a comprehensive assessment of credible options showing that reinforcement of the transmission network supplying Hummocks is justified 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	190
Fleurieu Peninsula Reinforcement	1. Load growth in the distribution system in the Fleurieu Peninsula region that causes the total load on the Willunga to Square Water Hole 66 kV sub-transmission line to exceed its thermal limit (72 MVA) 2. Successful completion of the Regulatory Test by the DNSP including a comprehensive assessment of credible options showing a transmission solution is economically justified 3. Formal request for a new regulated connection point from the DNSP 4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	210

Project Name	Trigger	Indicative Cost ($m Nominal)
Northern Suburbs Reinforcement	1. Load growth in the distribution system in the northern suburbs region that causes: • the total load on the Para to Elizabeth Heights 66 kV sub-transmission line to exceed its thermal rating (137 MVA) for an outage of the Munno Para 275/66 kV transformer; OR • the need to de-radialise supply to Gawler East. 2. Successful completion of the regulatory test or regulatory investment test for transmission (as applicable) including a comprehensive assessment of credible options demonstrating that a new or modified transmission connection point in the region is economically justified 3. Formal request for a new regulated connection point from the DNSP 4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	50
Port Pirie System Reinforcement	1. Addition of a step load in the Port Pirie area that causes: • the total load on the Bungama to Port Pirie 33 kV sub-transmission lines to exceed their thermal rating (84 MVA) for an outage of the Bungama to Port Pirie 132 kV transmission line or Port Pirie 132/33 kV transformer; OR • the total load on the grouped Bungama to Port Pirie connection points exceeding 93 MVA causing low voltage at Bungama for the loss of the single 200 MVA 275/132 kV transformer 2. Successful completion of the Regulatory Test or regulatory investment test for transmission (as applicable), including a comprehensive assessment of credible options demonstrating that a transmission reinforcement in the region is economically justified 3. Formal request for an expanded regulated connection point from the DNSP 4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	52
Upper South East Network Augmentation	1. Publication by AEMO of evidence of material constraints in the South East region of the transmission network 2. Successful completion of the regulatory investment test for transmission demonstrating positive net market benefits 3. Determination by the AER under clause 5.6.6AA that the proposed investment satisfies the regulatory investment test for transmission 4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	50

Project Name		Trigger	Indicative Cost ($m Nominal)
Riverland Reinforcement	1.	Publication by AEMO of available Murraylink dispatch into South Australia that is insufficient to provide adequate support to the Riverland causing thermal limitations on the Robertstown to Berri transmission lines	400
	2.	Successful completion of the regulatory investment test for transmission including a comprehensive assessment of credible options demonstrating that reinforcement of the Riverland is justified	
	3.	ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	
South East to Heywood Interconnection Upgrade	1.	Successful completion of the regulatory investment test for transmission demonstrating positive net market benefits	63
	2.	Determination by the AER under clause 5.6.6AA that the proposed investment satisfies the regulatory investment test for transmission	
	3.	ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	
Davenport Reactive Support	1.	Commitment to the temporary or permanent closure of Playford and Northern Power Stations during the South Australian summer period	42
	2.	Successful completion of the regulatory investment test for transmission showing installation of additional reactive support at Davenport is justified	
	3.	ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	
Mid North Connection Point	1.	Addition of a step load to the distribution system, in the upper north east of the mid-north region that causes the total load on the Bungama to Gladstone 33 kV sub-transmission line to exceed 14 MVA and causing voltage limitations in the distribution network	60
	2.	Successful completion of the regulatory test or regulatory investment test for transmission (as applicable), including a comprehensive assessment of credible options demonstrating that a transmission reinforcement in the region is economically justified	
	3.	Formal request for a new regulated connection point from the DNSP	
	4.	ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	

Project Name	Trigger	Indicative Cost ($m Nominal)
Upper North Region Line Reinforcement	1. Customer commitment to connect a step load along the Davenport to Pimba 132 kV transmission line that causes the total load to exceed 76 MW causing thermal limitations on the network 2. Completion of the regulatory investment test for transmission including a comprehensive assessment of credible options demonstrating that reinforcement of the transmission line is justified 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	60
East Terrace Transformer	1. Forecast load exceeding 270 MVA in the Adelaide Central Region 2. Completion of the regulatory investment test for transmission including a comprehensive assessment of credible options demonstrating that a second transformer at East Terrace substation is justified 3. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	23

16. Pricing Methodology

ElectraNet's Proposed Pricing Methodology, applicable from 1 July 2013 to 30 June 2018, contained minor amendments to:

- Reflect the changes to the Rules that have occurred subsequent to the approval of ElectraNet's current approved Pricing Methodology, specifically the Rule change of January 2010 which varied the provisions of clause 11.6.11 of the Rules; and
- Modify the standby provisions of section 6.12 of the Pricing Methodology to encourage customers to better manage their peak demand and reduce their impact on the transmission network at times of high network utilisation.

The AER's Draft Decision was to approve ElectraNet's proposed pricing methodology unamended. ElectraNet has not made any further revisions to the Proposed Pricing Methodology submitted with its original Revenue Proposal.

17. Negotiated Services

ElectraNet proposed minor revisions to the Negotiating Framework approved by the AER for the period 1 July 2008 to 30 June 2013 for the purposes of the forthcoming regulatory control period. The minor revisions sought to reflect changes required by the AER in subsequent revenue determinations relating to other TNSPs.

The AER did not approve ElectraNet's proposed Negotiating Framework, concluding that the proposal does not comply with the Rules requirements in clause 6A.9.5(c).

Further, the AER required that the following paragraphs of the proposed negotiating framework should be amended:

- paragraph 6.3.1, which seeks to give effect to sub-clauses 6A.9.5(c)(3)(i) and (ii) of the Rules;
- paragraph 7.2, which contains a citation error in referencing another part of ElectraNet's proposed negotiating framework; and
- paragraph 9.1.1, which seeks to give effect to clause 6A.9.5(c)(5) of the Rules.

ElectraNet has incorporated the required revisions in the AER's Draft Decision to its Negotiating Framework.

An amended version of the Negotiating Framework incorporating the required amendments is included with this Revised Revenue Proposal as Appendix N.

18. Cost Pass Through

In an application to the AER dated 29 August 2012,[245] ElectraNet nominated three additional cost pass through events to those generally applicable under the Rules for the purposes of the 2013-2018 regulatory control period, and proposed consequential changes to its self-insurance forecast.

This application was lodged in accordance with a Rule change made by the Australian Energy Market Commission on 2 August 2012.[246]

The AER in its Draft Decision approved the cost pass through events proposed by ElectraNet, subject to changes in the proposed definitions for two of the three events as follows:

- The proposed definition of a terrorism event was accepted as proposed (page 269);
- The AER requires that the definition of a natural disaster event be amended (page 269); and
- The AER requires that the definition of insurance cap event be amended (page 269).

In approving the cost pass through events, ElectraNet notes that the AER also accepted ElectraNet's proposed reduction in self-insurance allowance (page 270).

The sections below present ElectraNet's response to the specific matters raised in the AER's Draft Decision, and set out the revisions that ElectraNet has made in its revised Revenue Proposal in light of the Draft Decision, including where ElectraNet has not incorporated certain aspects of the Draft Decision.

18.1 Natural disaster event

AER Draft Decision

The AER has accepted a natural disaster event as a pass through event for the 2013-2018 regulatory control period. The AER is satisfied that ElectraNet has taken sufficient steps to avoid, mitigate and commercially insure against natural disasters.[247]

The AER's Draft Decision requires ElectraNet to make a number of changes to its proposed definition of a natural disaster event, specifically to:

- add a reference to the need for a flood, fire or earthquake to be 'major', in order to be considered a natural disaster and be eligible for consideration as a cost pass through event (page 273);
- add a reference to the event occurring within the 2013-2018 regulatory period (page 273); and

245 ElectraNet, Pass Through Event Proposal, August 2012.

246 AEMC, *Rule determination, National electricity amendment (cost pass through arrangements for network service providers) rule* 2012, 2 August 2012.

247 AER, Draft Decision, page. 272.

- add a reference to factors that the AER will have regard to in assessing a natural disaster event application, namely the insurance premium submitted by ElectraNet in its Revenue Proposal, the forecast operating expenditure allowed in the AER's final decision, and the reasons for that decision (page 274).

ElectraNet Response

ElectraNet has included in its revised Revenue Proposal an amended definition of a natural disaster event which reflects the AER's Draft Decision. However, as set out below, ElectraNet does not agree that the revisions in the Draft Decision to the definition of the natural disaster pass through event are necessary for the AER to approve ElectraNet's originally proposed definition.

First, in relation to the amendment to insert "major", ElectraNet submits that it is clear by virtue of the materiality threshold that applies to pass through events (being 1 per cent of the maximum allowed revenue for a TNSP in the relevant regulatory year)[248] that the event would be a "major" event. Similarly, as the AER notes in the Draft Decision, the use of the term "natural disaster" also carries with it the characteristic of being a "major" event.

Second, in relation to the amendment to specify the matters that the AER will have regard to in assessing a natural disaster event application, ElectraNet does not consider that it is consistent with the Rules to incorporate such matters in the definition of a pass through event.

ElectraNet appreciates the guidance that the AER is giving in indicating the kinds of matters that it considers will be relevant when it comes to assessing a particular pass through event and ElectraNet considers that it is appropriate for the AER to set these out in a Draft or Final Decision.

However, ElectraNet submits that the Rules do not permit the specification of a pass through event to extend to matters the AER will have regard to in assessing a pass through application.

This is because what the Rules require is a decision on the additional pass through events that are to apply for the regulatory control period,[249] not a specification of the matters the AER considers may be relevant when it comes to determine a pass through amount. The matters the AER is required to take into account in assessing a pass through amount are clearly set out in the Rules, one such matter being a catch-all, "any other factors the *AER* considers relevant".[250] ElectraNet submits that it is not permissible for the AER to bind itself to considering particular matters ahead of assessing a particular pass through application.

Notwithstanding the above comments, ElectraNet has incorporated the following definition of a natural disaster event reflecting the definition in the AER's Draft Decision:

> **A natural disaster event:** Any major flood, fire, earthquake or other natural disaster beyond the reasonable control of ElectraNet that occurs during the 2013-2018 regulatory control period and *materially* increases the costs to ElectraNet of providing *prescribed transmission services*.

248 Rules. definition of "positive change event" and "materiality".
249 Rules, clause 6A.14.1(9).
250 Rules, clause 6A.7.3(j).

For the avoidance of doubt, in assessing a natural disaster event application, the AER will have regard to:

- the insurance premium proposal submitted by ElectraNet in its Revenue Proposal;
- the forecast operating expenditure allowance approved in the AER's final decision; and
- the reasons for that decision.

For completeness, ElectraNet notes that the only difference between the above definition and that set out in the AER's Draft Decision is that the terms 'materially' and 'Revenue Proposal' appear above in italics, as defined terms under the Rules.

For the avoidance of doubt, ElectraNet also suggests that the AER's final determination should include at the commencement of the specified pass through events a statement to the effect that terms that appear in italics have the same meaning as those defined terms in the Rules.

18.2 Insurance Cap Event

AER Draft Decision

In the Draft Decision the AER has approved an insurance cap event as a pass through event for the 2013-2018 regulatory control period. The AER is satisfied that an insurance cap event represents the most efficient mechanism to address ElectraNet's insurance cap risks.[251]

The AER has, however, proposed a number of changes to the proposed definition of an insurance cap event.

Specifically, in its Draft Decision the AER:

- did not agree with the two triggers proposed by ElectraNet, as neither trigger requires ElectraNet to make a claim on an insurance policy, and proposed a change to the definition of the trigger for this event requiring that ElectraNet make a claim and receive a payment under a relevant insurance policy (page 276);
- included a reference in its proposed definition to the relevant policy limit being the higher of the policy limit at the time of the event that gives rise to the claim, or the policy limit at the time of the AER's final decision for the 2013-2018 regulatory period (page 276);
- removed the reference to 'costs that are likely to be incurred', as part of the proposed definition of an insurance cap event (page 276); and
- commented that it would expect to consider claims of negligence in determining whether or not the event was in the TNSP's control, for the purpose of its decision on the pass through application (page 275).

[251] AER, Draft Decision, page 274.

ElectraNet Response

ElectraNet appreciates why the AER has proposed a change to the definition to explicitly reference the making of a claim on an insurance policy by ElectraNet, and the receiving of a payment under an insurance policy.

However, limits under some insurance policies may restrict the number of times ElectraNet is able to make a claim under that policy, or may impose an aggregated total on all claims under that policy during any one period of insurance.[252]

As a consequence, it will not always be the case that ElectraNet is able to make a claim under a particular policy (e.g. if the number of allowed claims has already been reached). Even if a claim is made, ElectraNet may not receive a payment under that policy, where any aggregated claim limit has been reached.

The AER's proposed definition for an insurance cap event would mean that the pass through event would not be triggered in such cases, even though they clearly represent instances where ElectraNet faces an insurance cap risk. This would be contrary to the rationale for accepting this pass through event.

In order to address this issue, ElectraNet has modified the proposed triggers for an insurance cap event proposed by the AER, in order to also allow for an insurance cap event to be triggered in circumstances where:

> 'ElectraNet would have been entitled to make a claim or receive a payment under a relevant insurance policy but for the application of a relevant policy limit'.

The AER defines the *relevant policy limit* as the greater of:

- ElectraNet's actual policy limit at the time of the event that gives rise to the claim; and
- its policy limit at the time the AER made its final decision on ElectraNet's transmission determination proposal for the period 2013-2018.

The AER recognises in the discussion in the Draft Decision that the insurance cap event should cover liability claims in relation to insurance policies which were held in a previous regulatory period.[253] However, the AER's proposed definition of the *relevant policy limit* does not achieve this objective. The problem arises because the policy limit is defined:

> 'at the time the AER made its final decision on ElectraNet's transmission determination proposal for the period 2013-2018'.

The relevant factor, however, is the policy limit assumed by the AER in setting the operating expenditure allowance, whether that is for the 2013-2018 or earlier regulatory period. ElectraNet has therefore proposed a drafting change to address this issue and to give effect to the AER's intentions.

In accordance with the AER's Draft Decision, ElectraNet has incorporated an amendment to remove the reference to 'costs that are likely to be incurred' as part of the proposed definition of an insurance cap event, as any cost pass through applications made in relation to an insurance cap event would refer to a specific claim being made on an insurance policy by ElectraNet, and therefore would reflect actual costs.

[252] For example, bushfire liability insurance.
[253] AER, Draft Decision, page 276.

However, ElectraNet notes that the AER is incorrect in stating that the drafting of the cost pass through mechanism presupposes the recovery of actual eligible costs not likely costs.[254] The definitions contained in the Rules of both *eligible pass through amount* and *materiality* refer to costs that the TNSP 'has incurred and is likely to incur'.

The AER has commented that it would expect to consider claims of negligence in determining whether or not the event was in the TNSP's control, for the purpose of its decision on the pass through application. ElectraNet notes that a TNSP may reasonably take out insurance against being found liable due to negligence. Indeed, the AER has previously accepted that there should be no exclusion from the coverage of an insurance cap event for events arising out of an NSP's 'negligence, fault or lack of care'.[255]

Suggesting the possibility that a cost pass through application under the insurance cap event may not be approved if the liability claim in excess of the insurance cap arises due to negligence would be inconsistent with this position and with the rationale for the inclusion of an insurance cap event in the regulatory arrangements.

As flagged earlier by ElectraNet in its proposal for cost pass through events,[256] and as recognised by the AER in its Draft Decision,[257] the insurance cap event would not be triggered by unlawful conduct and gross negligence, as in this case the TNSP would not be able to make a call on its insurance cover.

In relation to the specification of matters that the AER will have regard to in assessing an insurance cap event cost pass through application as part of the definition of the event, as noted above, ElectraNet does not consider that it is appropriate or open to the AER to specify such matters. Notwithstanding this position, ElectraNet has incorporated this aspect of the AER's Draft Decision in its revised definition.

In summary, ElectraNet proposes that the definition of an insurance cap event for the 2013-2018 regulatory period be revised from that proposed by the AER as follows:

An insurance cap event: an event whereby:

1. ElectraNet:

    <u>a.</u> makes a claim and receives a payment under a relevant insurance policy;

    <u>or</u>

    <u>b.</u> <u>would have been entitled to make a claim or receive a payment under a relevant insurance policy but for the application of a relevant policy limit;</u>

2. ElectraNet incurs costs beyond the relevant policy limit; and

3. The costs beyond the relevant policy limit *materially* increase the costs to ElectraNet of providing *prescribed transmission services*.

For the purposes of this insurance cap event:

4. The relevant policy limit is the greater of:

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254 AER, Draft Decision, page 276.

255 AER, *Victorian electricity distribution network service providers Distribution determination 2011–2015, Final Decision,* October 2010, page 792, 793.

256 ElectraNet, *Pass Through Event Proposal*, August 2012, page 13.

257 AER, Draft Decision, page 275.

a. ElectraNet's actual policy limit at the time of the event that gives, or would have given, rise to the claim, and

b. ~~its policy limit at the time the AER made its~~ the policy limit that is commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the *AER's* final decision ~~on ElectraNet's transmission determination proposal~~ for the *regulatory control period* ~~2013-18~~ in which the relevant insurance policy is issued.

5. For the avoidance of doubt, in assessing an insurance cap event cost pass through application under rule 6A.7.3, the *AER* will have regard to:

   a. the insurance premium proposal submitted by ElectraNet in its *Revenue Proposal*;

   b. the forecast operating expenditure allowance approved in the *AER*'s final decision; and

   c. the reasons for that decision.

6. A relevant insurance policy is an insurance policy held during the 2013-2018 *regulatory control period* or a previous *regulatory control period* in which ElectraNet was regulated.

For completeness, ElectraNet again notes that the defined terms under the Rules in the above definition appear in italics.

19. Glossary

AASB	Australian Accounting Standards Board
ABS	Australian Bureau of Statistics
ACCC	Australian Consumer Competition Commission
ACT	Australian Competition Tribunal
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMD	Agreed Maximum Demand
AMP	Asset Management Plan
AOD	Average Outage Duration
APR	Annual Planning Report
AWOTE	Average Weekly Ordinary Time Earnings
CBD	Central Business District
CEG	Competition Economists Group
COAG	Council of Australian Governments
CPI	Consumer Price Index
DAE	Deloitte Access Economics
DNSP	Distribution Network Service Provider
DRP	Debt Risk Premium
EA	Enterprise Agreement
EBSS	Efficiency Benefit Sharing Scheme
EMCa	Electricity Market Consulting associates
EMC	Electromagnetic compatibility
EMS	Energy Management System
ESCOSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities
ETC	Electricity Transmission Code
EUAA	Energy Users Association of Australia
FDC	Finance During Construction
GDP	Gross Domestic Product
GSP	Gross State Product
GVA	Gross Value Added
GWh	Gigawatt hours
IT	Information Technology
ITMOS	International Transmission Operations and Maintenance Study
JPB	Jurisdictional Planning Body
LiDAR	Light Detection and Ranging
LPI	Labour Price Index

MAR	Maximum Allowed Revenue
MFP	Multifactor Productivity
MFS	Maloney Field Services
MITC	Market Impact of Transmission Congestion
MRP	Market Risk Premium
MW	Megawatt
MWh	Megawatt hours
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NERA	NERA Economic Consulting
NPV	Net Present Value
NTNDP	National Transmission Network Development Plan
NZIER	New Zealand Institute of Economic Research
ODRC	Optimised Depreciated Replacement Cost
OPSWAN	Operations Wide Area Network
OTR	Office of the Technical Regulator
PPI	Producer Price Index
PSC	Power Systems Consultants
PTRM	Post Tax Revenue Model
PV	Photovoltaic
RAB	Regulatory Asset base
RBA	Reserve Bank of Australia
RESIC	Resources and Energy Sector Infrastructure Council
RFM	Roll Forward Model
RIT-T	Regulatory Investment Test for Transmission
Rules	National Electricity Rules
SASDO	South Australian Supply and Demand Outlook
SCADA	Supervisory Control and Data Acquisition
SCAR	System Condition and Asset Risk
SCER	Standing Council on Energy and Resources
SG	Superannuation Guarantee
SKM	Sinclair Knight Merz
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan
STPIS	Service Target Performance Incentive Scheme
TAB	Tax Asset Base
TALC	Transmission Asset Life Cycle
TNSP	Transmission Network Service Provider
TUOS	Transmission use of system
WACC	Weighted Average Cost of Capital

20. Appendices

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