SA Power Networks

Revised Regulatory Proposal 2015-20

Page left blank intentionally

Table of Contents

Page left blank intentionally

1. Introduction

On 31 October 2014, SA Power Networks submitted a regulatory proposal supported by a number of attachments and other supporting documents and information (together the **Original Proposal**) to the Australian Energy Regulator (**AER**) in accordance with the National Electricity Rules (**NER** or **Rules**), setting out the revenue we require to manage our electricity network in a safe, reliable and prudent manner for the regulatory control period from 1 July 2015 to 30 June 2020 (**2015-20 RCP**).

The AER published a Preliminary Determination in response to our Original Proposal on 30 April 2015 (**Preliminary Determination**) and, in accordance with clause 11.60.4(a) of the NER, invited written submissions on the revocation and substitution of that Preliminary Determination. Following consideration of stakeholder submissions, the AER will revoke its Preliminary Determination and substitute it with its Final Determination on 31 October 2015.

SA Power Networks has carefully considered the findings of the AER's Preliminary Determination and, in accordance with clause 11.60.4(b) of the NER, has prepared this document and the various attachments and other supporting documents and information referred to in this document (together the **Revised Proposal**) as a submission to the AER in the form of revisions to our Original Proposal. For clarity, the Original Proposal read together with and subject to the Revised Proposal, forms our current regulatory proposal.

Attachments and other supporting documents and information referred to in this document have been provided to the AER on an electronic storage device. SA Power Networks' revised responses to the Reset Regulatory Information Notice (**RIN**) issued by the AER in August 2014 have also been included on the electronic storage device. These revised responses are supporting information and therefore form part of the Revised Proposal.

This document and its principal attachments have been prepared specifically for the current regulatory process and are current as at the time of lodgement.

Information contained on the electronic storage device, although forming part of the Revised Proposal, includes documents and data that are part of SA Power Networks' normal business processes, and are therefore subject to ongoing change and development.

1.1 Purpose of the Revised Proposal

SA Power Networks' Original Proposal was the subject of compliance confirmation, public consultation and detailed review by the AER and its consultants. The Revised Proposal sets out revisions that SA Power Networks has made to its Original Proposal to incorporate, where SA Power Networks considers it to be appropriate, changes arising from the Preliminary Determination made by the AER for the 2015-20 RCP.

However, SA Power Networks is of the view that the AER, in making its Preliminary Determination has made a number of decisions that are not in the long-term interests of consumers and are contrary to the National Electricity Objective (**NEO**). The Revised Proposal outlines those decisions and explains why they do not contribute to the NEO to the greatest degree.

1.2 Structure and approach

SA Power Networks has reviewed all of the matters raised by the AER in its Preliminary Determination including, in particular, where the AER has made adjustments to particular aspects of SA Power Networks' Original Proposal.

In the Revised Proposal, we have made changes to incorporate many of the AER's adjustments to particular aspects of our Original Proposal, but this should not be taken as acceptance by SA Power Networks of the rationale provided by the AER or its consultants for any relevant adjustment.

Where SA Power Networks has revised an aspect of its Original Proposal (which, for clarity, may be, or may include, a relevant attachment or attachments and/or supporting information), the revision of that aspect may have been addressed in any one or more of a variety of ways. For example, by a statement of acceptance of the AER's adjustment, or by updating, substituting, adjusting, adding to, reiterating, reinforcing, amplifying or replacing particular aspects of our Original Proposal.

Where SA Power Networks has not revised an aspect of its Original Proposal (which again, for clarity, may be, or may include, a relevant attachment or attachments and/or supporting information), that aspect of the Original Proposal remains the current regulatory proposal.

In addition, SA Power Networks has updated the information required to be submitted by clause S6.1 (Contents of building block proposals) and the AER's Reset RIN, to reflect our Revised Proposal. This updated material is either contained in the relevant chapter of the Revised Proposal, the revised Reset RIN data template or supporting information forming part of this Revised Proposal.

The structure of our Revised Proposal is as follows:

Table 1.1: Chapters of the Revised Proposal

Chapter	Topic
1	Introduction
2	Summary
3	Our customer engagement
4	Classification of services and negotiating framework
5	Control mechanisms – standard control services
6	Peak demand and sales forecasts
7	Forecast capital expenditure
8	Forecast operating expenditure

Chapter	Topic
9	Pass-through events
10	Incentive schemes
11	Shared assets
12	Regulated asset base
13	Weighted average cost of capital
14	Depreciation
15	Estimated cost of corporate income tax
16	Revenue and pricing
17	Alternative control services
	Shortened forms
	Attachments

Page left blank intentionally

2. Summary

2.1 SA Power Networks

SA Power Networks is the principal electricity distribution network services provider (**DNSP**) in South Australia. We recognise that electricity is the lifeblood of our community and we understand the responsibility we hold in the delivery of our services to all South Australians.

SA Power Networks has a proud history of providing cost-efficient, safe and reliable electricity supply to our 850,000 customers. Recent benchmarking data gathered across the industry by the Australian Energy Regulator (**AER**) shows that, in addition to our network being one of the most reliable, we are also the most efficient distributor in the National Electricity Market (**NEM**) on a state wide basis.

The South Australian energy industry is on the cusp of transformational change driven by new technologies and our customers' changing needs and expectations. Energy usage patterns are already changing radically in South Australia. Substantial wind and solar renewable energy in South Australia is displacing traditional generation plant as evidenced by the mothballing of gas fired power generation at AGL's Torrens Island and Alinta Energy recently announcing that it will close its Northern and Playford coal fired stations at Port Augusta by 2018 or sooner.

2.2 SA Power Networks' Original Proposal

On 31 October 2014, we lodged our Regulatory Proposal for the 2015-20 regulatory control period (**RCP**) (**Original Proposal**) outlining the revenues and costs required to enable us to continue to deliver the level of safe and reliable electricity supply that our customers are accustomed to receiving, and that we are required to, and have been asked to, provide. The Original Proposal also included expenditure that will enable SA Power Networks to develop the network infrastructure and related services to cater for the changing expectations of our customers and to take all reasonable steps to meet our legal and regulatory obligations and requirements. In particular, the Original Proposal included capital and operating expenditure to:

- keep the power on for South Australians;
- respond to the increasing frequency and impact of severe weather events;
- ensure safety for the community is appropriately addressed, including through bushfire mitigation;
- grow the network in line with South Australia's needs;
- ensure that power supply meets voltage and quality standards;
- serve customers' needs now and in the future with an emphasis on new and emerging technologies and customer demands for more accurate and real time information;
- ensure our infrastructure fits in with our streets and communities; and
- continue to invest in our people and facilities to have the capabilities to meet these challenges.

2.3 AER's Preliminary Determination

On 30 April 2015, the AER released its Preliminary Determination which made substantial reductions to significant components of our Original Proposal including capital expenditure ($797 (June 2015, $ million)), operating expenditure ($298 (June 2015, $ million)), regulatory depreciation ($402 (nominal, $ million)), allowances for return on capital ($554 (nominal, $ million)) and tax allowance ($227 (nominal, $ million)).

SA Power Networks has reviewed all of the adjustments made by the AER in its Preliminary Determination, and the AER's reasons for making those adjustments, and has incorporated a number of these adjustments into our Revised Proposal. This does not mean that SA Power Networks necessarily agrees with the AER's reasons for making each of these changes. SA Power Networks has, however, focussed its response on those issues that it considers crucial to maintaining the safety and reliability of the network and promoting the long term interests of its customers.

SA Power Networks has serious concerns regarding some of the preliminary decisions made by the AER in its Preliminary Determination.

Although we have incorporated a number of the AER's adjustments into our Revised Proposal, we are concerned that many important aspects of the AER’s Preliminary Determination are incorrect, unwarranted and inconsistent with the National Electricity Law (**NEL**) and National Electricity Rules (**NER**).

Specifically, it is our view that the AER has:

- misunderstood our legal and risk management obligations under the *Electricity Act 1996* (SA) in rejecting expenditure associated with our proposed bushfire mitigation program ($93 million[1]);
- given little weight to the clear concerns of our customers as identified through our comprehensive, robust and representative customer engagement program (**CEP**) by rejecting, amongst other things:
  - the proposed undergrounding for bushfire safer places and other high risk sections of the network ($129 million);
  - the proposed change in approach to tree trimming which includes the benefits of a tree removal and replacement program ($32 million);
  - the proposed investment of $30 million to harden our network to reduce the impact on our customers of loss of power arising from the growing frequency and severity of storms (including high winds and lightning strikes in particular);
  - the proposed investment to monitor and control the low voltage network to facilitate greater penetration of solar panels and new technologies such as battery storage and electric vehicles ($20 million); and
  - the proposed investment of $78 million to relocate, or place underground network infrastructure to improve road safety;
- made numerous omissions and modelling errors in the Preliminary Determination. Examples of these types of errors are:
  - with the transfer of certain metering services from standard control services (**SCS**) to alternative control services (**ACS**), deducting the associated operating costs of $11 million for these services from SCS but not adding these costs into the operating cost allowance for ACS; and
  - using the wrong five year period in modelling replacement capital expenditure, resulting in an understatement of $51 million over the 2015-20 RCP;
- departed from its publicly stated open and transparent regulatory process by applying an alternate approach to calculating asset depreciation. This alternate method effectively transfers $318 million in depreciation charges to future generations. Despite the significance of this item, it was

[1] In this Summary, all dollar amounts are in real June 2015 $, except where otherwise stated.

not raised in any of the discussions with the AER during its six month period of review of our Original Proposal;

- not fully appreciated the legislative and regulatory requirements of the electricity and work health and safety laws in South Australia with which we must comply. In particular, the AER has failed to understand our obligation to take all reasonable steps to address safety matters, and has mistakenly concluded that undertaking a 'standard' cost benefit analysis is an appropriate way of determining what is ‘a reasonable step’ in this context. This has affected the expenditure associated with our proposed bushfire mitigation program, and has resulted in the AER rejecting a number of our operating expenditure step changes;
- publicly stated that the rate of change in the energy industry is increasing[2] and that the industry will be significantly impacted by the growing penetration and use of new and emerging technologies, and yet has allowed no expenditure for SA Power Networks to address these changes over the RCP;
- wrongly assumed that there will be no operational and investment impact on our business with the introduction of metering contestability in mid-2017;
- ignored the investment and cost increases that we will incur in preparing for the introduction of cost-reflective tariffs from July 2017; and
- continued to adopt its stated position on rate of return and gamma notwithstanding that these positions are considered to be inconsistent with the NER, the independent advice received by the AER, and precedent decisions by the Australian Competition Tribunal.

SA Power Networks considers that, in some key respects, the AER has not correctly applied its obligations under the NEL and the NER in arriving at its Preliminary Determination. We are of the view that the AER erred in taking the position that its task is only to determine 'overall revenue allowances' and has, as a result, failed to give SA Power Networks the opportunity to recover at least the efficient costs it will incur in the 2015-20 RCP (as it is entitled to under section 7A(2) of the NEL).

In its Preliminary Determination, the AER states that:

> *'[In 2012 and 2013 the] NEL and NER were amended to provide greater emphasis on the NEO and greater discretion to us. The amended NER allows, and the AEMC has encouraged us, to approach decision making more holistically to meet overall objectives consistent with the NER and RPPs.'*[3]

These statements have led the AER to form the view that in assessing SA Power Networks’ proposed expenditure it must only assess the 'overall revenue allowance' of a DNSP and its contribution to the NEO.

Based on this approach, the AER in its Preliminary Determination, made a decision to approve 32.3% less revenue than SA Power Networks proposed in its Original Proposal.

In arriving at this decision, the AER saw the most important factors impacting SA Power Networks' costs in the 2015-20 RCP as:

- an improved investment environment compared to the 2010-15 RCP, which translates to lower financing risks required to attract efficient investment;

[2] Paula Conboy, *AER White Paper submission*, November 2014 – ‘Electricity networks are entering a period of fundamental change. Drivers such as demand uncertainty, network cost pressures, the need to integrate renewable generation and electric vehicles, and the change brought about by new technologies, will impact the way energy is delivered to and by customers in the future.’

[3] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, 30 April 2015, page 44.

- few changes to the operating environment facing SA Power Networks with respect to risk or regulatory obligations; and
- forecast demand, which is expected to remain reasonably flat over the 2015-20 RCP, reducing the requirement for growth-related capital expenditure.

At a total revenue level, these factors, in the AER's view, provide a background against which SA Power Networks, operating prudently and efficiently, could provide distribution services with materially less revenue than it proposed for the 2015-20 RCP.[4]

This finding is fundamentally incorrect.

We demonstrated in our Original Proposal that we will face growth in prudent and efficient costs over the 2015-20 RCP due to escalating input costs as well as the need for additional work to meet demand, customer expectations and our regulatory obligations and requirements. However, the AER failed to have proper regard to these facts in its Preliminary Determination.

SA Power Networks simply cannot meet these growing costs solely by improving efficiency elsewhere in its business. The AER in considering our Revised Proposal and making its Final Determination needs to properly take into account:

- that SA Power Networks is an efficient DNSP performing above the AER’s efficient benchmark;
- an approach to operating costs which is not more stringent on efficient businesses than the approach it has applied to businesses below but near the efficient benchmark;
- that SA Power Networks is facing material and ongoing increases in costs and such increases cannot be accommodated solely by adopting new business practices;
- the AER’s disallowance of step changes in the Preliminary Determination is undermining the AER’s own efficiency incentive schemes by effectively establishing an asymmetric regime that is skewed towards the likelihood of penalties rather than rewards; and
- a broader perspective on what constitutes efficiency by acknowledging that it is economically efficient to allow expenditures to fund projects that provide broader benefits to consumers.

In short, at a high level, we are concerned that the AER has not fulfilled its task under the NEL and NER and this has resulted in the AER forming constituent decisions that do not comply with the NER and do not lead to an outcome that contributes to the achievement of the National Electricity Objective in the NEL.

2.4 Revised Proposal

SA Power Networks has assessed the AER’s reasoning for its decisions in the Preliminary Determination, taken into account the strong input and feedback from our customers during our extensive customer engagement program over the last two and a half years, and obtained legal advice as to the steps we must undertake to comply with our regulatory obligations and requirements over the 2015-20 RCP.

As a consequence, our Revised Proposal includes the following key adjustments (in June 15 dollar terms, unless stated otherwise) to the AER’s Preliminary Determination:

---

[4] AER, *Preliminary Decision: SA Power Networks Determination 2015-16 to 2019-20*, 30 April 2015, page 10.

- $75 million in replacement capital expenditure to correct modelling and escalation errors made by the AER;
- $86 million in safety augmentation capital expenditure to enable our bushfire mitigation program to be implemented and to deliver on customer concerns;
- $144 million in capital expenditure to invest in the non-network category including our IT systems, fleet and facilities;
- operating expenditure to meet regulatory obligations and requirements ($64 million), improve vegetation management ($33 million) and address the impacts of our capital investment program ($30 million);
- $60 million for real increases in labour costs and output growth;
- an updated rate of return of 7.09% which, together with changes to our regulatory asset base, adjust the rate of return on assets revenue component by $348 million (nominal, $);
- $237 million (nominal, $) in our tax allowance to be consistent with a previous decision of the Australian Competition Tribunal plus higher overall proposed revenue;
- $505 million (nominal, $) in our regulatory depreciation allowance after applying our revised asset register approach plus capital and CPI; and
- $21 million of combined ACS capital and operating expenditure to address omissions and modelling errors made by the AER.

Had the AER's Preliminary Determination been made on the basis of our Revised Proposal then a network price reduction of 8.1% would have applied on 1 July 2015 with no real increases for the remainder of the 2015-20 RCP. The price path for the remaining four regulatory years of the RCP will be determined by the AER in its Final Determination.

SA Power Networks considers the Revised Proposal delivers outcomes which are materially preferable to the Preliminary Determination, including for reasons as set out in Section 13.12.

We look forward to engaging in an enhanced, open, transparent and fulsome process with the AER as this Revised Proposal is considered and a Final Determination is made by the AER by no later than 31 October 2015.

This Revised Proposal is structured to largely mirror the building block chapters outlined in our Original Proposal. The following paragraphs provide further details of the key chapters of this Revised Proposal.

2.4.1 Customer Engagement (Chapter 3)

Specific amendments were made to the NER in 2012 to ensure DNSPs conducted more meaningful and transparent engagement with their customers to ensure expenditure proposals for the next RCP addressed customers' concerns.

SA Power Networks embraced this change and initiated a technically rigorous, comprehensive and robust customer engagement program (**CEP**), titled 'TalkingPower'. The design of TalkingPower was undertaken in conjunction with independent experts and completed in 2012, to allow enough time for effective engagement and customer feedback to be incorporated into our plans for the 2015-20 RCP.

The program that followed provided us with a depth and breadth of information on customer concerns and expectations that had never before existed in Australia. These were summarised into 13 'customer insights' and incorporated 'willingness to pay' research on a small number of those insights which we integrated into our plans. This culminated in approximately $300 million of proposed capital expenditure and $100 million of proposed operating expenditure to implement customer-supported or customer-driven initiatives.

However, the AER's Preliminary Determination supported none of these initiatives.

In its Preliminary Determination, the AER stated that it gave less weight to SA Power Networks' CEP results because of some negative comments within a (very limited) number of submissions it received from stakeholders. We discuss this more comprehensively in Chapter 3 but, essentially, we believe the AER has erred in not giving more weight to our CEP and not approving funding for the initiatives that arose from it.

This is a crucial moment in the use of customer engagement in the regulatory process. SA Power Networks has responded to the Rule changes in 2012 by investing heavily in its CEP. We have found the detailed feedback of our customers to be invaluable in formulating a regulatory proposal which responds to their needs and preferences.

If there is one message that has come through clearly from our CEP, it is that electricity customers have a range of needs and preferences, which will vary over time and with different combinations of price and quality outcomes. An approach which seeks to attribute to all customers a demand for prices to be reduced in all circumstances and at all costs, is simply inconsistent with the feedback that SA Power Networks has received. We have sought to elicit and analyse the views of our customers in an informed and impartial manner. Where we have sought to rely on customers' views to support specific expenditure proposals we have done so with care. We urge the AER to take a considered approach to the preferences expressed by SA Power Networks' customers, and to give weight to all of those preferences.

2.4.2 Capital Expenditure (Chapter 7)

In this Revised Proposal, we have submitted a revised capital expenditure forecast for SCS for $386.8 million (excluding equity raising costs) above that allowed by the AER in its Preliminary Determination. The main areas covered by this revised forecast include:

- Replacement expenditure – $74.7 million based on:
  - correcting the AER's modelling by using the correct five-year forecast in pole replacements;
  - applying a logically consistent growth factor to expenditure categories not specifically modelled by the AER; and
  - adjusting for updated escalations and overheads.
- Augmentation expenditure – $130.4 million based on:
  - our proposed bushfire mitigation expenditure;
  - our proposed expenditure to ensure we have protection systems that comply with our legal and regulatory obligations;
  - our proposed expenditure for work programs to harden the network against storms and improve performance of low reliability feeders;
  - our proposed expenditure to manage compliance with the metering Rule change and regulated quality of supply requirements; and
  - adjusting for updated escalations and overheads on total augmentation spend; and
- Non-network expenditure – $143.5 million based on:
  - our proposed IT expenditure for asset management, regulatory information notice (**RIN**) compliance, metering Rule change and network operating systems; and

- fleet and property expenditure associated with additional resourcing.

We discuss our revised capital expenditure forecast in more detail in Chapter 7 of this Revised Proposal.

2.4.3 Operating Expenditure (Chapter 8)

In its Preliminary Determination, the AER accepted our 2013/14 (adjusted) SCS operating expenditure as an efficient base year. However, it then rejected almost all of our proposed step changes and all of our customer-driven initiatives.

In this Revised Proposal, we propose a $196.1 million increase in operating expenditure (excluding debt raising costs) above that which the AER allowed in its Preliminary Determination. The main areas requiring additional funding include:

- Step changes – an increase of $135.9 million associated with:
  - asset inspections for 'no access' poles and increased frequency of asset inspections in bushfire risk areas;
  - compliance with a number of other legal and regulatory obligations, including those required to transition to cost reflective tariffs and enable metering contestability; and
  - our customer driven initiatives, including more frequent vegetation management; and
- Trend – an increase of $60.2 million due to input cost (labour) and output growth escalations.

We discuss our revised operating expenditure forecast in more detail in Chapter 8 of this Revised Proposal.

2.4.4 Rate of Return (Chapter 13)

In the 2015-20 RCP, SA Power Networks will be allowed to recover significantly less revenue than in the 2010-15 RCP if the Preliminary Determination is sustained. This is partly due to a significant reduction in the return on capital revenue component, resulting from the AER's preliminary decision on SA Power Networks' weighted average cost of capital (**WACC**).

SA Power Networks acknowledges the current financial market environment is considerably different to that immediately after the 2008 global financial crisis when the AER determined the current WACC for SA Power Networks. As a result, a lower WACC for the 2015-20 RCP is appropriate.

Notwithstanding this, we are concerned about, and do not support, the AER's decisions on a number of the underlying parameters that the AER has used to determine a nominal vanilla WACC of 5.45% for the 2015-20 RCP (down from 9.8% in the 2010-15 RCP).

We elaborate on our concerns in Chapter 13 of this Revised Proposal where we propose that the WACC should be increased to 7.09%. We propose to recover an additional $348 million in the return on capital revenue component, reflecting our proposed WACC and changes to the regulated asset base (**RAB**) (discussed below).

2.4.5 Asset base and depreciation (Chapters 12 and 14)

In our Original Proposal, we submitted a depreciation allowance using the same methodology for the calculation of remaining asset lives as applied in the AER's 2010 Determination for SA Power Networks. In its Preliminary Determination, the AER adopted a different approach for determining remaining asset lives. In Chapter 14 of this Revised Proposal we propose a more accurate method to determine remaining asset lives.

We propose that the SCS RAB will move from $3,778 (nominal, $ million) at 1 July 2015 to $4,990 (nominal, $ million) at 30 June 2020 and that depreciation allowances be adjusted by $505 (nominal, $ million) relative to the Preliminary Determination. These changes largely arise from:

- remaining asset lives being calculated using the baseline approach as detailed in Chapter 14;
- our revised capital expenditure forecast; and
- the impact of a lower CPI escalation of the RAB.

2.4.6 Tax (Chapter 15)

We propose that the AER adjusts its taxation allowance by $237 million to reflect the higher overall proposed revenue and a lower value of imputation credits, or 'gamma', of 0.25, compared with the AER's proposed gamma of 0.4.

We discuss our revised tax allowance in more detail in Chapter 15 of this Revised Proposal.

2.4.7 Alternative Control Services (Metering Services) expenditure (Chapter 17)

In our Original Proposal, metering services expenditure was based on our 'Tariff and Metering Business Case' which had as its primary aim the cost-efficient introduction of cost-reflective 'demand' tariffs to small customers during the 2015-20 RCP. That proposal was made at a time when, although arrangements to increase metering contestability were expected in the 2015-20 RCP, the timing and nature of these changes were unclear. Our strategy required installing manually read interval (Type 5) meters for all new and replacement situations from July 2015 and transitioning to reading meters on a monthly basis in 2017.

Since then, a draft Rule change issued by the Australian Energy Market Commission (**AEMC**) in March 2015 has clarified that, after 1 July 2017, only remotely read interval (Type 4) meters may be installed by a 'Metering Coordinator', appointed by retailers. The installation of Type 4 meters will enable SA Power Networks to implement its new demand tariffs without the need to install Type 5 meters or move to monthly reading of manually read meters. This significantly reduces our capital and operating expenditure requirements for ACS in the 2015-20 RCP.

We largely accept the AER's preliminary decisions for ACS expenditure but believe the AER has made a number of errors and omissions in determining its expenditure allowances. In order to correct these errors and omissions, we propose that the allowed expenditure be adjusted as follows:

- allowed capital expenditure by $8 million; and
- allowed operating expenditure by $11 million.

We discuss our revised ACS expenditure in more detail in Chapter 17 of this Revised Proposal.

3. Our customer engagement

Amendments were made to the National Electricity Rules (**NER**) in 2012 to specifically require a distribution network service provider (**DNSP**) to engage in more meaningful and transparent engagement with electricity consumers to ensure that capital and operating expenditure forecasts include expenditure to address consumers' concerns. Those amendments formed one (but a very significant) part of a paradigm shift in the way that the long term interests of consumers are intended to be taken into account in furtherance of the National Electricity Objective (**NEO**). While we consider that we have always been at the forefront of consumer engagement in the electricity industry, SA Power Networks wholeheartedly embraced this change and initiated an extensive Customer Engagement Program (**CEP**) even before the NER amendments were made, and undertook a significant portion of its CEP as the AER's Consumer Engagement Guideline was being developed.

The SA Power Networks CEP:

- contained, or was based on, critical elements that were designed and overseen by independent, highly credentialed and well regarded experts;
- was technically rigorous and robust and leveraged recent stakeholder experience from the United Kingdom;
- was actively participated in by over 13,000 electricity consumers;
- was representative of our customer base by including all customer segments and geographical regions;
- was unbiased; and
- gave rise to statistically significant outcomes and results.

In its Preliminary Determination, the AER indicated that it gave little weight to that CEP and its results. In fact, from the Preliminary Determination, SA Power Networks has been unable to identify any evidence that the AER gave any weight to the CEP and its results.

On the other hand:

- the AER received a very limited number of submissions in relation to our Original Proposal – excluding SA Power Networks and Consumer Challenge Panel 2 (**CCP2**), only 27 stakeholders made a submission;
- of those, 10 made no comment on the CEP;
- although the remaining 17 made one or more negative comments, observations or assertions about aspects of the CEP, of those, all bar three provided no purported analysis to substantiate or support those comments, observations or assertions; and
- in relation to the three that did purport to provide some analysis in support of their comments, observations and assertions (namely SACOSS, Business SA and the South Australian Financial Counsellors Association), those analyses are not technically rigorous, robust or statistically significant (for reasons discussed later in this chapter).

Notwithstanding this, in its Preliminary Determination, the AER gave weight to those very limited number of submissions.

In short, in arriving at its Preliminary Determination, SA Power Networks is of the view that the AER erred in two fundamental respects:

- the AER failed to properly have regard to and take into account, and therefore to give appropriate weight, to the concerns raised by South Australian customers as identified during SA Power Networks' appropriate and robust CEP and included in our expenditure forecasts; and
- the AER gave significant weight to other stakeholders' unsubstantiated, or technically lacking, assertions and subjective observations on the SA Power Networks CEP.

This chapter elaborates on these critical issues and provides even greater support and weight for the consumer driven / supported proposals contained in SA Power Networks' Original Proposal (as varied by aspects of this Revised Proposal).

However, before moving on, there are two important matters that SA Power Networks brings to the attention of the AER and stakeholders:

- Given that we distribute electricity to the entire community, we of course have a broad and diverse range of customers. These customers have a range of financial circumstances and some unfortunately face significant financial difficulties generally in meeting their living expenses. However, our role and obligation is to provide safe and reliable distribution services in a prudent and efficient manner for the benefit of all of our customers.

  The regulatory regime requires that our programs and expenditure be tailored to meet the demands and requirements of all customers - it does not contemplate that the specific financial circumstances of one group in the community should impact on programs and expenditure that are for the benefit of the majority of customers. Our CEP was designed and carried out so as to be inclusive and representative of all customers, whilst recognising that outcomes must largely reflect the demands and requirements of the significant majority.
- That does not mean that SA Power Networks is not concerned about the cost of delivered electricity to South Australians, including disadvantaged customers. Whilst consumer hardship programs generally are the responsibility of Government, it is because we are concerned that we sought to introduce this year a new program for the benefit of the most disadvantaged of this State's hardship customers

3.1 Rule requirements

3.1.1 National Electricity Objective

The National Electricity Objective (**NEO**), set out in the National Electricity Law (**NEL**), is to:
'promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to -

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

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

3.1.2 National Electricity Rules – capital/operating expenditure factors

Although it has been clear that the interests of consumers are paramount ever since the NEL was passed in 1996, significant changes were made to the NER in 2012 in order to place an even greater focus on taking into account consumer interests in both the formulation by DNSPs, and the assessment by the AER, of regulatory proposals.

One of the principal changes introduced in 2012 to make this focus even more explicit, was the insertion of clauses 6.5.6(e)(5A) and 6.5.7(e)(5A) into the NER:

- Clause 6.5.6(e)(5A) requires the AER to have regard to the extent to which a DNSP's operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by that DNSP in the course of its engagement with electricity consumers; and
- Similarly, clause 6.5.7(e)(5A) requires the AER to have regard to the extent to which a DNSP's capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by that DNSP in the course of its engagement with electricity consumers.

Another important change made at the same time was the introduction of clause 6.8.2(c1) into the NER which requires a DNSP to describe how it has:

- engaged with electricity consumers in developing its regulatory proposal; and
- sought to address relevant concerns identified as a result of that engagement.

3.1.3 Better Regulation Consumer Engagement Guideline

To add even further weight to this increased focus on the addressing of electricity consumers' concerns, the AER published its Consumer Engagement Guideline as part of its 'Better Regulation' reform program to provide a framework to integrate consumer engagement into Network Service Providers' (**NSPs'**) business-as-usual operations, and to set out the AER's expectations of how NSPs should engage with consumers.

SA Power Networks' CEP aligned with the requirements of this Guideline, with the Stakeholder Engagement Standard (**AA1000SES**) and the International Association of Public Participation (**IAP2**) framework.

3.1.4 National Electricity Rules – capital/operating expenditure objectives

Although there is now a clear added focus on electricity consumers' concerns, those concerns may only be legitimately addressed by a regulatory proposal if they reasonably reflect the operating / capital expenditure criteria set out in clauses 6.5.6(c) and 6.5.7(c) of the NER which, in turn, are aimed at achieving the operating / capital expenditure objectives. Those objectives are:

1) meet or manage the expected demand for standard control services over that period (**first objective**);
2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services (**second objective**);
3) to the extent that there is no applicable regulatory obligation or requirement in relation to:
   - (i) the quality, reliability or security of supply of standard control services; or
   - (ii) the reliability or security of the distribution system through the supply of standard control services,

   to the relevant extent:
   - (iii) maintain the quality, reliability and security of supply of standard control services; and
   - (iv) maintain the reliability and security of the distribution system through the supply of standard control services,

   (**third objective**); and

4) maintain the safety of the distribution system through the supply of standard control services (**fourth objective**).

3.1.5 Specific South Australian regulatory requirements

In addition to the requirements under the NER, SA Power Networks has State-based regulatory obligations which it must meet. They, importantly, include (but are not limited to) the obligation under section 60(1) of the *Electricty Act* 1996 to 'take all reasonable steps to ensure that our infrastructure is safe and safely operated'.

This duty, coupled with our duty to maintain and operate our distribution system in accordance with good electricity industry practice (under NER clause 5.2.1(a)), requires us to have regard to objectively determined standards of safety (ie what would a reasonable and prudent electricity distribution system operator faced with the same conditions and circumstances as apply to SA Power Networks do to ensure that the distribution system is safe and safely operated and is maintained and operated in a manner that is consistent with the degree of skill, diligence, prudence and foresight expected from Australian electricity distribution system operators).

Given that these standards of safety are required to be objectively determined, they will, by definition, change over time as what constitutes reasonable steps and good electricity industry practice is influenced by industry developments and learnings <u>and by the expectations and requirements of electricity consumers</u>.

All of the above rules, laws and requirements are of critical importance and relevance to:

- why and how SA Power Networks has engaged with electricity consumers;
- the outcomes from that engagement;
- how those outcomes have, as required by the NER, informed SA Power Networks' Original Proposal (as varied by this Revised Proposal); and
- why those outcomes are required to be given significant weight by the AER.

3.2 SA Power Networks' Original Proposal

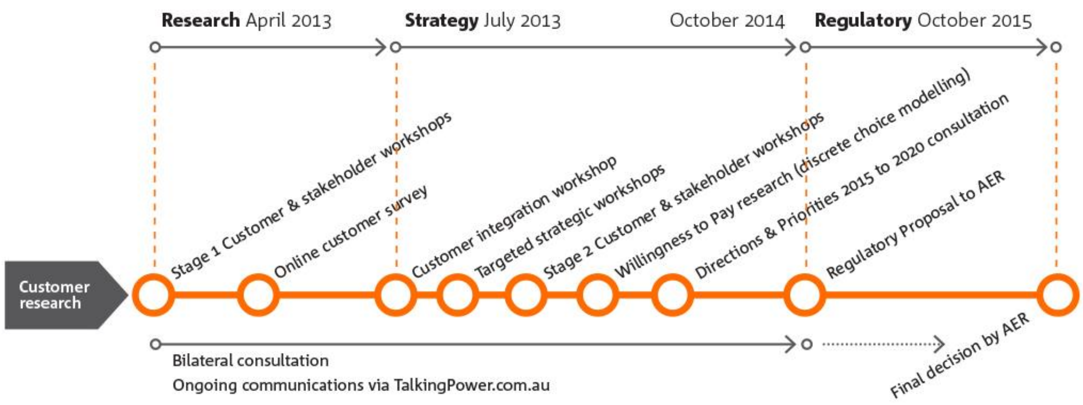
3.2.1 Our customer engagement

SA Power Networks has, for many years, had a solid reputation for building effective relationships and dialogue with our customers, whose concerns, which we regularly monitor, are increasingly influencing our many activities, projects and processes. This solid platform, combined with recent stakeholder engagement experience from the United Kingdom (**UK**), was leveraged to develop our CEP, the design of which was completed some 12 months before the AER's Consumer Engagement Guideline was finalised. This timing was no accident; it was important that our CEP was commenced early enough to allow for effective engagement as well as provide enough time to consider customer feedback and factor it into our planning for the 2015–20 RCP. And our dedication and commitment to the CEP is evidenced by the hundreds of hours of executive and management effort and time expended throughout the CEP, as well as the material expenditure incurred in engaging independent and highly regarded expert advisors and engagement service providers.[5]

[5] The external costs incurred by SA Power Networks were in excess of $800,000.

Our CEP, titled 'TalkingPower', which is presented in simplified form in Figure 3.1 was and is consistent with, and meets the principles and other process requirements of, the AER's Consumer Engagement Guideline, and aligns with the Stakeholder Engagement Standard (**AA1000SES**) and the International Association of Public Participation (**IAP2**) framework.

Figure 3.1: SA Power Networks' TalkingPower Customer Engagement Program

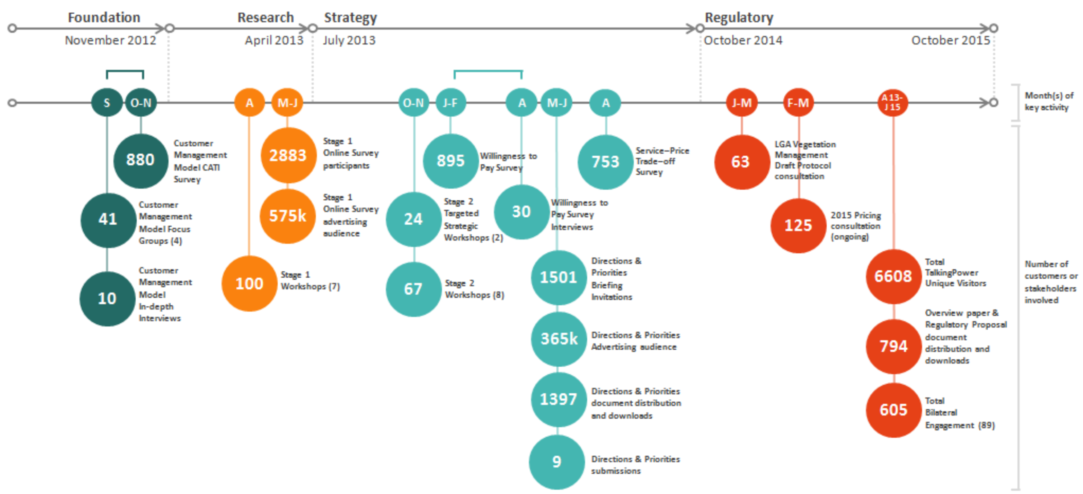


SOURCE: SA POWER NETWORKS 2014

TalkingPower covered all customer segments and key stakeholder groups across South Australia. Through a variety of media and platforms, we interacted with over 13,000 electricity consumers, and opportunities to participate were widely promoted as indicated by Figure 3.2. A comprehensive range of service areas, and short and long term customer issues were explored by using extensive qualitative and quantitative research undertaken by independent, highly credentialed and well regarded experts in their field. Furthermore, our senior management were heavily involved in the program.

From its outset, TalkingPower set an indicative and easily understood distribution price path for the 2015–20 RCP which was that the basket of distribution services would be delivered with annual network price changes limited to no more than CPI. This was very important in helping customers come to a personal judgment of the value and balance in relation to SA Power Networks' potential services and investments. In specific cases where more targeted proposals were being researched, incremental bill impacts were explicitly indicated.

Figure 3.2: TalkingPower – opportunities and number of customers involved in key engagement activities



Source: SA Power Networks 2014

As indicated in Figure 3.2, TalkingPower encompassed three distinct stages:

- The '**Research**' stage – This stage focused on 'listening' to customers and providing them with objective information about the energy industry and network services to assist customers' understanding and enable customers to voice their concerns and expectations as inputs into the development of possible services and investments for the 2015–20 RCP. This involved professionally-facilitated (largely) qualitative workshops across the State, involving a sample of South Australian electricity consumers to ensure insights captured were representative of all customers. Residential participants were recruited by a dedicated market research agency to achieve a robust sample of participants with mixed attributes such as gender, age demographic, billing segment, native language, disability and solar panel use. A broad range of business customers and stakeholders from Government, councils and welfare or special interest groups also attended the workshops. These workshops were followed by an online survey to collect quantitative data. The online survey achieved 2,883 responses, comparing very favourably with similar recent surveys by UK distributors.
- The '**Strategy**' stage – This stage focused on progressing and integrating customer expectations and concerns into our planning for the 2015–20 RCP. This involved:
  - planning workshops (where Deloitte provided independent analysis of customer concerns and expectations) involving SA Power Networks' executives and business leaders who considered opportunities within our business to address these concerns;
  - two collaborative workshops to develop strategies in relation to the undergrounding of power lines and the clearance of vegetation around power lines;
  - some limited, but targeted, Willingness to Pay (**WTP**) research, confined to undergrounding of some power lines and clearing vegetation around power lines, which was used to test the extent of customers' financial support for such strategies; and
  - release and consultation on our 'Directions and Priorities 2015 to 2020' to deliver clarity and transparency on our service proposals and the prices customers could expect to pay for them. In a first for the NEM, the consultation document was effectively a customer-friendly 'draft' regulatory proposal, and submission opportunities were widely promoted across the State. There were nine submissions in response to this document. Notably, some organisations that later made strident submissions in relation to aspects of our Original Proposal did not make a submission nor provide input on their views during this very important consultation opportunity.
- The '**Regulatory**' stage – This stage focussed on the AER's evaluation of our Original Proposal. This stage includes ongoing customer engagement including our CEP, vegetation management consultation with local government, pricing consultation, and consultation with businesses, representatives from industry groups and the majority of the stakeholders who had provided submissions to the AER on our Regulatory Proposal.[6]

TalkingPower was facilitated by independent specialists from Deloitte and Second Road in order to provide confidence to both us, and stakeholders, that customer views were fairly represented and that our findings would be technically rigorous and robust. These two organisations, and The NTF Group, also provided expertise at various times in key aspects relating to the design and implementation of the program.

All outputs and source materials from our program are available on our **TalkingPower.com.au** website.

[6] Senior executives from SA Power Networks personally met, or held teleconferences, with those stakeholders and, following each meeting or discussion, followed up in writing with each of them.

3.2.2 Customer insights

TalkingPower provided us with a depth and breadth of information on customer concerns and expectations that has simply not previously existed. This allowed us to address those concerns and expectations in our plans and provided confidence that, as required by the NER, our Original Proposal aligned with the short and long term interests of electricity consumers in South Australia.

Our customers' concerns and expectations, as drawn from our TalkingPower qualitative and quantitative research initiatives, are summarised in the 13 key 'insights' shown in Figure 3.3.

Figure 3.3: Key customer insights

Incorporation of customer insights into our Original Proposal

The integration of customer concerns and expectations into our planning was a very important part of developing our Original Proposal and was a critical element of the TalkingPower program. Table 3.1 illustrates how the engagement outcomes were factored into numerous aspects of our Original Proposal.

Table 3.1: How our Original Proposal addressed customer concerns

Key customer service areas	Key links to our expenditure forecasts
'Keeping the power on for South Australians' Chapter 9	Asset replacement, condition monitoring, Kangaroo Island cable, asset inspections, substation maintenance
'Responding to severe weather events' Chapter 10	Network reliability, hardening the network, telecommunications network
'Safety for the community' Chapter 11	Bushfire risk mitigation, road safety, asset inspections, vegetation management
'Growing the network in line with South Australia's needs' Chapter 12	Network augmentation, security, customer connections, National Energy Customer Framework customer charging changes
'Ensuring power supply meets voltage and quality standards' Chapter 13	Voltage regulation and monitoring, flexible load management, facilitating connection of distributed energy resources
'Serving customers now and in the future' Chapter 14	IT systems supporting billing, customer service and cost reflective tariffs
'Fitting in with our streets and communities' Chapter 15	Power Line Environment Committee, vegetation management
'Capabilities to meet our challenges' Chapter 16	IT systems, property, vehicle fleet and other resources, supporting delivery of our forecast work programs and strategies

3.3 AER's Preliminary Determination

In its Preliminary Determination there is limited discussion by the AER about, and extremely little analysis of, SA Power Networks' CEP or the outcomes arising from it.

The AER did express the view that it considered *'the consumer engagement undertaken by SA Power Networks is a positive step'*[7] but went on to conclude that it is a '*work in progress*'[8] and stated that it had given the consumer engagement results *'less weight than if the consumer engagement approach had been broadly supported in submissions.'*[9]

One aspect of the CEP was the WTP research that SA Power Networks had engaged The NTF Group to carry out. That research was limited, being confined to potential undergrounding of some power lines and some potential additional clearance of vegetation around power lines. The AER engaged Oakley Greenwood to conduct a limited desk-top peer review of that WTP research. The Oakley Greenwood review '*did not find any assumptions in the WTP research that caused any concern regarding its methodological soundness or that would potentially compromise the validity of its results*'.[10] Oakley Greenwood did however note that the testing of vegetation management and undergrounding in the WTP research was relatively narrowly focussed (as it was designed to be).

After referencing some of the submissions it had received, which questioned whether our consultation activities had included relevant service and price alternatives (such as the CCP2 and SACOSS submissions in particular), the AER observed that it had given less weight to the wider CEP results than would have been the case if submissions had broadly supported the CEP approach.

The AER's Preliminary Determination supported none of the customer supported or customer driven initiatives set out in our Original Proposal. In fact, the AER rejected entirely:

- all WTP-related proposals, namely:
  - the proposed change in our vegetation management approach; and
  - the targeted undergrounding of parts of the network, including for additional bushfire and road safety reasons.
- our bushfire safety initiatives, securing supply to Bushfire Safer Places;
- our hardening the network initiatives;
- our proposed systems supporting the introduction of cost-reflective tariffs and our demand side participation proposals; and
- our communications initiatives to address customer preferences for improved customer service and community safety information.

These initiatives constituted approximately $300 (June 2015, $ million) of capital expenditure and $100 (June 2015, $ million) of operating expenditure as put forward in our Original Proposal.

[7] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, Overview, page 15.
[8] Ibid.
[9] Ibid.
[10] Oakley Greenwood, *Peer review of the Willingness to Pay Research submitted by SAPN*, 20 April 2015, page 4

3.4 SA Power Networks' response to AER Preliminary Determination

3.4.1 Our comprehensive CEP

Compliance with Guideline principles and processes

As noted above, in order to provide enough time for effective engagement with electricity consumers and to factor feedback into the planning and proposals for the 2015–20 RCP, we completed the design of our CEP some 12 months before the AER's Consumer Engagement Guideline was finalised. In doing this, we engaged reputable, highly regarded, independent experts to help with the design (and subsequent facilitation) of our CEP to ensure that the highest standards of independence and quality were brought to bear. In particular, Deloitte and The NTF Group were engaged to design and implement the following three quantitative research processes as part of our CEP:

- Deloitte, Stage 1 Online Consumer Survey;
- The NTF Group, Targeted Willingness-to-Pay Research; and
- The NTF Group, Service-Price Research.

The AER's Consumer Engagement Guideline provides a high level framework based on best practice principles drawn from AA1000SES and IAP2. The internationally recognised IAP2 accepts that there is no one single 'correct' way to undertake stakeholder engagement, but is a best practice framework designed to assist organisations to select the appropriate level of engagement for different stakeholder groups.

In November 2014 we engaged Banarra, an independent certified sustainability assurance expert, to undertake an assessment of our CEP against the principles and other process requirements of the AER's Consumer Engagement Guideline and other relevant standards (such as AA1000SES). Banarra's report is provided at Attachment C.1 to this Revised Proposal.

Banarra concluded that our CEP was substantively designed in compliance with those principles and process requirements. In the case of some of those principles and process requirements, Banarra found that not only had we met them, we had in fact exceeded them in some respects. Banarra commented:

> *'Key strengths of the TalkingPower program included: the use of collaborative, accessible and timely engagement mechanisms; the transparent disclosure and reporting of key information and consultation outputs to stakeholders; and a clear commitment by SA Power Networks to using the consultation outputs to assist its decision-making and to inform the design of the 2015-20 Regulatory Proposal.'*[11]

On the other hand, Banarra did find that there were a few aspects where the CEP did not fully meet a principle or process requirement, however, in relation to those instances, Banarra noted that those gaps related primarily to aspects of the TalkingPower program that were designed or completed prior to the publication of the AER Guideline. For example, formally documented engagement processes were not fully established during the early stages of the program.[12] This aspect has little or no bearing on the findings of the CEP, but in any case we will address all identified items as we continually refine our customer engagement process for ongoing application. Banarra further noted that in their

[11] Banarra, Attachment C.1 – *SAPN Banarra Stakeholder Engagement Assessment – Final Gap Analysis Report,* 24 April 2015
[12] Ibid

experience, '… *these aspects are typically the last to be comprehensively addressed by those with maturing stakeholder engagement management systems*.'[13]

Put simply, Banarra did not find any material compliance concerns with the approach taken with SA Power Networks' comprehensive CEP.

Stakeholder representation and sampling

Our wide ranging CEP engaged with all key customer segments across the State on multiple occasions. In addition, throughout the CEP, SA Power Networks conducted a program of bilateral engagement and consultation with representatives from Government, businesses, business associations, welfare and special interest groups.

Through a variety of advertising and other media, the Deloitte *Online Consumer Survey* that formed part of Stage 1 of our TalkingPower program was widely promoted to ensure it was accessible to all South Australians regardless of their bill paying status, location or age. The online survey was broadly promoted using newsprint, radio, social media and digital media on multiple occasions to ensure as many South Australians as possible had the opportunity to participate. Demographic analysis by Deloitte[14] shows that the sample of 2,829 residential respondents captured a representative sample of the South Australian population. In addition, statistical tests and analyses were used to test for statistical confidence and statements made as key findings (the 13 consolidated customer insights discussed in our Original Proposal) were only made where the response achieved at least 95% significance.[15]

We also note that collaboration with the Essential Services Commission of South Australia (**ESCoSA**) was a feature of the online survey approach. As indicated earlier, ESCoSA retains responsibility for setting service levels in South Australia through its Service Standards Framework (**SSF**). To help improve the readiness of our regulatory and institutional frameworks for the future, the survey also contained a series of questions regarding reliability of supply that were designed by ESCoSA. This process was facilitated independently of both organisations by Deloitte. ESCoSA then subsequently utilised findings from the online survey as an input in validating and amending the SSF to apply to SA Power Networks for the 2015–20 RCP. Obviously, as they were part of the same survey implementation, the sampling approach that underpins the new ESCoSA-determined SSF for South Australia applies equally to SA Power Networks' online survey results.

The sample of 895 respondents deployed by The NTF Group in the targeted WTP research was representative of the SA population.[16] In addition, the sample was post-weighted and correlated to Australian Bureau of Statistics (**ABS**) data to ensure it was representative in terms of both demographics and household solar penetration.[17]

A total of 753 South Australian residents completed the Service-Price survey and data was post-weighted to ensure the proportion of respondents falling into each ESCoSA region was representative, including the proportion of customers receiving a Government concession.[18]

Our CEP's qualitative and quantitative research has provided clear, robust and statistically significant insights into the material concerns of electricity consumers that are representative of the views of the population of South Australia.

---

[13] Ibid

[14] Deloitte, *Online Consumer Survey Report*, page 6 (Attachment 6.5 to Original Proposal).

[15] Ibid.

[16] The NTF Group: SAPN *Targeted Willingness to Pay Research – Research Findings*, 30 July 2014, page 28

[17] Clean Energy Regulator; RET, April 2014

[18] The NTF Group: *Service-Price Research Findings*, 23 October 2014, slide 4

Weight – our consumer engagement

Given the above, from an objective, analytical perspective, the AER (as required by the Rules) should have given significant weight to the robust nature of the wide ranging CEP and the representative, statistically significant results that flowed from it. Stakeholder and CCP2 submissions did not provide any statistically significant analyses which would indicate that the concerns raised by customers during our CEP should not be properly considered by the AER.

The AER's consideration of SA Power Networks' wide ranging CEP in its Preliminary Determination was limited to the targeted WTP research carried out for SA Power Networks which was a small part of the CEP. There is no evidence in the Preliminary Determination that the AER undertook any appropriate assessment of our broader CEP. Indeed, on page 13 of the Overview section of the Preliminary Determination, the AER states that:

> *'To investigate the views expressed by … submissions [received from the CCP2 and SACOSS], we engaged a specialist consultant, Oakley–Greenwood, to assess SA Power Networks' consumer engagement methodologies and reported results. In its report, Oakley–Greenwood noted the consumer engagement was relatively narrowly focussed.'*

Oakley Greenwood was not engaged by the AER to review the overall CEP and no such observation was made by Oakley Greenwood.

Oakley Greenwood was engaged to conduct a limited desk-top peer review of SA Power Networks' and its consultant's WTP findings and the assumptions and methodologies that underpinned our WTP research. Oakley Greenwood did state that in respect of that targeted WTP research:

> *'it is difficult to see the WTP Survey as a comprehensive assessment of SAPN customers' willingness to pay for improved service: it [is] simply too narrow in its scope.'*[19]

As such, Oakley Greenwood's comment was not, and obviously could not have been, about SA Power Networks' broader CEP.

As will be discussed later, neither did the CCP2 undertake any comprehensive analysis of SA Power Networks' CEP.

In light of the above, SA Power Networks contends that significant weight should have been given to our wide ranging, representative CEP and the results flowing from it.

[19] Oakley Greenwood, Peer Review of the Willingness to Pay Research Submitted by SAPN, 20April 2015, page 16.

3.4.2 Stakeholder submissions

Throughout SA Power Networks' CEP there was strong support for both the process of engagement and the outcomes arising from it. For example, participants in the research stage workshops consistently indicated strong levels of support, as evidenced below:

- 92% of participants agreed or strongly agreed the workshop met their expectations;
- 96% enjoyed the collaboration in the workshop; and
- 94% would like to see further workshops run in the same fashion.

Notwithstanding this, there were a number of submissions lodged in response to our Original Proposal which questioned aspects of the program.

Submissions in response to Original Proposal

The AER appears to have given significant weight to the submissions received on the Original Proposal because it stated that it has given

> *'less weight [to SA Power Networks' CEP] than if the consumer engagement approach had been broadly supported in submissions.'*[20]

The AER received a very limited number of submissions in relation to either our Original Proposal or the AER's Issues Paper relating to it. Excluding SA Power Networks and the CCP2, only 27 stakeholders made a submission.

Of those stakeholders, 10 made no comment on our CEP.

Although the remaining 17 made one or more comments, observations or assertions about one or more aspects of the CEP, only three purported to provide any analysis to substantiate or support any of their comments, observations or assertions. Those were SACOSS, Business SA and the South Australian Financial Counsellors Association (**SAFCA**).

The remaining 14 stakeholders did not provide any analysis, evidence, substantiation or verification in support of their comments, observations or assertions. Examples of some of their comments are (with emphasis added by underlining):

> *'While the research demonstrates SA Power Networks' commitment to understand the community drivers, the Government is concerned that the results do not align with the concerns expressed by South Australian electricity consumers at large. Certainly over the last 5 years the Government has received <u>an increasing number of letters</u> from the community expressing concern with impact of escalating electricity prices.*
>
> *One specific example, which demonstrates this point well, relates to last year's approval by the AER of an additional $35.1 million pass-through cost for vegetation clearance costs resulting from increased rainfall. Following the AER's decision the Government <u>received a number of letters</u> expressing customer concern regarding the additional charge.'*[21]
>
> *'In seven community forums we held [with Council of the Ageing South Australia members] in 2014, the rising cost of electricity, water and housing was a recurring*

[20] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, Overview, page 15.
[21] SA Minister for Mineral Resources and Energy, Government of South Australia Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2015-20, 30 January 2015, page 12

theme. Consumers consistently told us of their anxiety in opening their latest electricity bill and of trying to understand why it had yet again risen.'[22]

'Customers do value these things [being reliable, safe and secure electricity supply], however what they value even more highly – or at the very least, as highly – is low-cost electricity. This was not adequately reflected in the proposal.'[23]

'The Greens also reject the assumptions of SAPN's proposal, which are based on Willingness To Pay (WTP) surveys and focus testing. … Furthermore we are not satisfied that feedback was obtained from a statistically significant sample size, given the scope of the service provision to South Australians. 13,000 respondents to a survey is not adequate in determining WTP or any other measure when the service provision is to 1.5 million people.'[24]

SA Power Networks contends that the AER should place limited weight on such assertions or claims made by stakeholders where no evidence or substantiation has been provided in support. SA Power Networks must (and of course should) provide evidence or substantiation in support of its arguments and proposals. But the same standard must be applied to other stakeholders by the AER, otherwise there is no legitimate basis for the AER to give more weight to the claims and assertions of those stakeholders than the arguments and proposals of SA Power Networks.

SA Power Networks has approached its legal obligations under the NER with the utmost good faith, as noted above, and important aspects of the CEP were designed and overseen by highly regarded, well recognised, independent experts such as Deloitte, Second Road and The NTF Group. The professional credibility of organisations of the calibre of Deloitte, Second Road and The NTF Group is founded on research processes that are sound, robust and reflective of generally accepted research and engagement principles and processes.

So that there is no misunderstanding, SA Power Networks is very concerned about the cost of delivered electricity to South Australians. Accordingly, although distribution represents only one component (and not the most substantial component) of that cost, we took appropriate steps in formulating our Original Proposal to balance the concerns of consumers for having low cost electricity supply whilst maintaining the safety, reliability and quality of our distribution network and seeking to ensure the network meets customers' changing expectations. These considerations were clearly articulated in Chapter 17 of our Original Proposal. In our 2015/16 Annual Pricing Proposal, SA Power Networks sought to introduce a new social tariff for the benefit of the most disadvantaged of this State's hardship customers.

As noted above, only three stakeholders, being SACOSS, Business SA and SAFCA, provided any information in support of their comments, observations or assertions. However, a close review of this information shows that these analyses are contentious and generally not adequately robust or statistically significant. SA Power Networks engaged The NTF Group to review and assess the research presented by SACOSS and Business SA from the perspective of accepted professional market research principles. The results of those reviews are at Attachments C.2 and C.3. In summary:

---

[22] COTA SA, Submission to the Australian Energy Regulator Price Determination for SA Power Networks 2015-20, 30 January 2015, page 2

[23] Ibid, page 3

[24] Hon. Mark Parnell MLC, SA Power Networks Regulatory Proposal – Greens SA Submission, 30 January 2015, page 1.

Sampling theory means provided respondents are randomly drawn from the population of interest, results derived from samples are projectable to that population. For example, the results of research based on a random sample of 900 SA households are reflective of all SA households, within a margin of sample error of +/- 3.3%.

- The SACOSS survey was focused on financial stress, relationships with electricity retailers, extreme weather events, ability to pay bills and disconnections, and was undertaken during a 'high bill' period for customers. No reference to distribution services nor SA Power Networks was made in the survey, and yet the survey results are somehow purported to be directly related to SA Power Networks' Regulatory Proposal;
- SACOSS has repeatedly stated that the price-service trade-off is a critical element in considering the level of network investment that should be approved by the AER yet we observe that the SACOSS survey neither provided respondents with contextual information nor requested any response on real world trade-offs that would be encountered as a result of a decision to have lower electricity prices; and
- The Business SA survey, answered by only 167 businesses, was not professionally designed and contained a leading introduction and questions which had the potential to bias results.

In relation to SAFCA, we note that the information it provided to support its submission appears to be anecdotal feedback from a number of unspecified agencies, and as such no statistical validity can be given to the SAFCA survey results.

The NTF Group findings in Attachments C.2 and C.3 detail a number of additional observations and findings which show that the research underpinning some of the claims in the SACOSS and Business SA submissions is not sufficiently robust or statistically significant.

SA Power Networks therefore contends that little weight should have been given by the AER to the results of the research submitted by SACOSS, Business SA and SAFCA for the purposes of supporting their submissions on SA Power Networks' Original Proposal.

CCP2 assessment of our CEP

The CCP2 members have two primary objectives under their charter, with the second objective being:

> *'advising the AER on the effectiveness of network businesses' engagement activities with their customers and how this engagement has informed, and been reflected in, the development of their proposals.'*[25]

While it would be reasonable to expect that the CCP2 might undertake an analysis of our CEP or engage a third party expert to do so, SA Power Networks has not seen any submissions or other materials that suggest that this occurred.

The CCP2 had very limited engagement or discussion with SA Power Networks about the CEP in the lead up to SA Power Networks submitting its Original Proposal. That engagement was confined to one short segment (<u>of approximately 15 minutes</u>) in a single meeting at SA Power Networks' offices on 25 March 2014.

The CCP2, which was appointed to 'challenge' our proposals and the findings of the AER on behalf of electricity consumers, did not engage on our CEP and made few comments in its submission on our Original Proposal. On reflection this tends to indicate that the CCP2 gave limited attention to the second objective under its charter (noted above). With regard to matters that were raised by the CCP2, we engaged The NTF Group to review these comments. The NTF Group's key findings are set out below (with Attachment C.4 containing their full report):

- We agree with the CCP2 view that providing a level of regulatory and industry understanding among respondents assists them in providing valid feedback. SA Power Networks used its senior

[25] AER's Consumer Challenge Panel: Description, Charter and Evaluation Criteria, 10 April 2013, page 3

executives to provide educative information in workshop settings, and in the quantitative on-line survey, targeted educative information was provided in the survey instrument, to the extent practicable;

- The CCP2 view that WTP research 'is still in its infancy' is incorrect. WTP research uses choice modelling methodology which has been used across a large number of willingness to pay studies for several decades, and has been accepted by IPART and ESCoSA. To assist respondents to the WTP research in making price-service trade-offs explanations were given as to the proportion of their bill accounted for by electricity distribution as well as the total electricity bill impact of their choices;
- Further, and contrary to comments made by a CCP2 representative in the AER's public forum on 10 December 2014, network price/charges reductions were adequately explored in the CEP research. SA Power Networks commissioned the NTF Service-Price survey (refer to Attachment 17.3 of the Original Proposal) which showed results consistent with similar surveys from other jurisdictions, namely that the vast majority (80%) of households would prefer to pay the current cost for the current reliability level, 11% would prefer to pay more for a more reliable standard of service and 9% would prefer to pay less for a less reliable standard of service;
- SA Power Networks confirms that samples used in both the Deloitte and The NTF Group surveys as part of the CEP were representative of the population and post-weighted in accordance with industry best practice; and
- The preconception of the CCP2 that low income households cannot have diverse views, including showing support for service options that they regard as valuable and that they are willing to pay for, is simplistic and does not reflect the reality coming from SA Power Networks' survey results from these customers.

<u>In light of the above, SA Power Networks contends that little or no weight should have been given by the AER to the very limited number of submissions it received from stakeholders and from the CCP2 that were critical of the CEP.</u>

Positive support for the CEP over the 24 month program

SA Power Networks is concerned that the AER appears to have adopted a view that because many stakeholders (who participated in our CEP) did not make submissions to the AER about their support for our CEP that their silence indicates a lack of support for it. There is no validity in such a view.

It is also to be expected that unfavourable submissions <u>will</u> be made by organisations whose roles include advocacy with respect to cost proposals by utilities.

On the other hand, there are a large number of positive statements about our CEP that were quoted in our Original Proposal (the number of which significantly outnumbers the 17 submissions received by the AER that made a negative comment about our CEP) and the overwhelming support from participants in the program is detailed in the various CEP reports that have been progressively added to our **TalkingPower.com.au** website.

The AER is required to 'have regard' not only to submissions it receives from stakeholders, but also to the substantive evidence provided to it in our CEP. The legal obligation to do so must be carried out appropriately. In our view the AER has failed to meet that obligation.

Weighting by the AER

It follows from the above that, instead of concluding in its Preliminary Determination that it should give more weight to negative stakeholder submissions than to SA Power Networks' CEP and its results, the AER should in fact have reached the opposite conclusion.

3.4.3 WTP research - A small but important part of our CEP

The one aspect of our CEP that received consideration in the AER's Preliminary Determination is our targeted WTP research. Accordingly, we have provided some specific consideration to the rationale for the WTP research, stakeholder comments on that research, the independent review of the WTP research commissioned by the AER, and the AER's and CCP2's assessment of that research.

Rationale

As we had fully embraced the 'shift' under the NER to even greater and more meaningful consumer engagement, SA Power Networks decided to go even further than 'engagement' and adopt a progressive approach of using design thinking collaboration and limited, but targeted, WTP research as part of our extensive CEP. At the outset, however, a WTP exercise was only contemplated to be implemented if the early stages of the CEP identified that there was a valid case to do so.

As such, the WTP research was the final stage of a targeted exploration of customer concerns. Potential areas for further detailed analysis came from participants in our CEP. The selected topics of vegetation management and undergrounding of power lines emerged as key areas of focus for our customers. To progress these matters we undertook specific 'design thinking' collaborative engagement workshops that were facilitated by Second Road. These workshops developed a number of key strategies to deliver on longer term outcomes for the benefit of customers. Once significant work was completed on potential pricing impacts related to the ideas that emerged from the collaborative workshops, the WTP research was only then conducted. The WTP research, and the methodology leading up to it, was sophisticated and innovative in the context of Australian network regulatory processes. Details of this sophisticated approach are to be found in our Original Proposal and in Attachment 16.6 to that document.

The resultant WTP research was limited to two aspects only arising out of the CEP – some vegetation management activities and some undergrounding of power lines in high bushfire risk areas, bushfire risk areas and non-bushfire risk areas. It is pleasing to note that SACOSS was supportive of such areas being considered, saying in its submission to the AER that 'SACOSS agrees with SAPN's choice of service improvements to test; these do seem to represent issues of importance for many in the community.'[26]

<u>Against the background of proposed total revenue in our Original Proposal of approximately $4.575 billion, our limited, but targeted, WTP research was confined to proposed capital expenditure and operating expenditure initiatives that would contribute approximately $65 million[27] - or only 1.4% - of our proposed total revenue.</u>

In the Australian regulatory context, which many describe as an essentially 'inputs-based' regime (unlike the outputs-based RIIO regime in the UK where WTP research is currently applied more comprehensively), this limited-in-scope, yet progressive, application of WTP was, appropriately in our view, both prudent and pragmatic considering the expenditure factor in clauses 6.5.6(e)(5A) and 6.5.7(e)(5A) of the NER requiring that the concerns of consumers be addressed.

---

[26] SACOSS, *Submission to Australian Energy Regulator on SA Power Networks' 2015-2020 Regulatory Proposal*, January 2015, page 26

[27] The proposed enhanced vegetation management opex initiative amounted to approximately $32 million over five years, and the combined proposed bushfire and road safety undergrounding capex initiative amounted to approximately $206 million over five years. Return on and of capital for the capex initiatives (at the WACC proposed in our Original Proposal) would have resulted in a revenue contribution of approximately $33 million over five years, resulting in a total WTP initiatives revenue contribution of $65 million (ie $32m + $33m) over five years.

The WTP research was designed and carried out by independent and highly regarded experts in this field, The NTF Group. SA Power Networks contends that this research is sound, robust and technically rigorous.

Stakeholder submission

SACOSS was the only stakeholder which made a submission that provided any analysis on our targeted WTP research.

We consider that SACOSS' assertions are incorrect and are not substantiated by the AER's own consultant, Oakley Greenwood, which in fact supported The NTF Group methodology. We engaged The NTF Group to review the SACOSS assertions, and its key findings are below:

1) SACOSS stated 'the use of online surveys skews the sample' – it is clearly evident in the WTP report submitted with the Original Proposal that the respondents were not recruited online (even though the survey was administered online).
2) SACOSS raised doubt about the legitimacy of sample weighting – the WTP report submitted with the Original Proposal clearly states that the sample accurately reflected ABS data.
3) SACOSS casts doubt over the way in which costs were presented to respondents – to assist respondents to the WTP research in making price-service trade-offs, explanations were given about the proportion of their bill accounted for by electricity distribution, as well as the total electricity bill impact of their choices.
4) SACOSS appears to infer an association of our WTP study with 'push polling' – it is self-evident that none of the characteristics of push polling (large numbers of respondents, brief surveys of less than 60 seconds and no analysis of response data) apply to WTP research.

The results of The NTF Group review of the SACOSS submission with respect to the WTP research are at Attachment C.5.

AER and CCP2 assessment of WTP

The AER engaged Oakley Greenwood to carry out a desk-top peer review of SA Power Networks' and its consultant's WTP findings and the assumptions and methodologies that underpinned that WTP research.

SA Power Networks was advised by AER officers on 17 March 2015 that Oakley Greenwood was about to be engaged to carry out this task. The date of Oakley Greenwood's report is 20 April 2015. Oakley Greenwood therefore had well under five weeks in which to commence its review, formulate its conclusions and publish its report. Moreover, Oakley Greenwood had a very limited 'scope of work' and was given limited materials by the AER to review. Those are far from a set of circumstances that lend themselves to being able to provide a robust piece of analysis – particularly given the focus on, and importance of, serious consumer engagement under the NER.

Despite the constraints imposed on them, Oakley Greenwood concluded that, apart from one assumption made as part of the WTP research, they

> *'did not find any assumptions in the WTP research that caused any concern regarding its methodological soundness or that would potentially compromise the validity of its results.'*[28]

[28] Oakley Greenwood, *Peer Review of the Willingness to Pay Research Submitted by SAPN*, 20 April 2015, page 4

Notwithstanding the Oakley Greenwood conclusion noted above, the AER, in its Preliminary Determination, raised a number of concerns in relation to the WTP research.[29] We engaged The NTF Group to review and assess the AER's concerns and the Oakley Greenwood report. The full reports are shown at Attachments C.6 and C.7. Key findings include:

- Regarding the sample not being representative: The AER is correct that only residential customers were included in the WTP research. However, the sample was representative of all South Australian households. The AER then goes on to assert that *'the proportion of respondents from the [Eastern Hills and Fleurieu Peninsula] EH and FP region was 50% higher than was required to be representative… [that] this is problematic because the EH and FP region is affected by more interruptions … [and] this may mean that those residing in the EH and FP region may be willing to pay more'.* This is factually inaccurate. Those living in metropolitan areas have a higher stated willingness to pay, therefore if anything, the 12 percentage point over-representation of respondents in EH and FP would have understated the level of consumer willingness to pay;
- Presentation of choices: The AER appears to have repeated one of the unfounded assertions made by SACOSS regarding the presentation of choices. The AER's own consultant, Oakley Greenwood, rejected this criticism. However, Oakley Greenwood did make the point that the description of choice scenarios should have stated outcomes. It was not possible for SA Power Networks to draw verifiable causal links between some of the improvement initiatives tested and real world outcomes (eg every X km of undergrounding in bushfire areas would reduce the number of bushfires by Y). In line with the conservative and prudent approach SA Power Networks and NTF applied to the design of the WTP, we elected to exclude outcomes we could not objectively verify. While we agree with the theory espoused by Oakley Greenwood, it was not feasible in this instance;
- The limited scope of the study: The WTP research was just one component of a much larger body of work (ie the SA Power Networks CEP). While the limited scope helps to maximise the efficiency and effectiveness of the WTP study (eg by reducing respondent cognitive burden), it is also the case that wider application of WTP to, say, areas of existing prescriptive regulatory obligation, would have been pointless. The targeted WTP research was aimed at selected aspects of customer preference that emerged from the wider CEP, and could thereby make a valid and new contribution to SA Power Networks' service proposals; and
- The basis on which the WTP findings were translated into service improvements: The 'NTF approach' starts by taking the generally accepted 50% threshold, for which there is academic support and historical precedent. Then, because of the conservative and prudent principle applied to the research design, NTF imposed two further constraints: 1. The '50% accepted' convention was lifted to 55%; and 2. This 55% threshold had to be achieved in each of the three core segments (ie residential, residential solar PV and residential hardship customers). The 'NTF approach' is based on convention and academic learning, but with additional constraints through the two part test. This is also consistent with approaches to political voting, whereas the alternative method put forward by Oakley Greenwood is interesting but untested.

Weighting by the AER

SA Power Networks therefore contends that the limited WTP research was in fact solid, robust and technically sound. It follows from the above that, instead of concluding that little if any weight should be given to SA Power Networks' WTP research, the AER should have reached the opposite conclusion.

3.4.4 Conclusion – AER's 'jump' from WTP criticisms to CEP criticisms

It is evident from the submissions made to the AER in relation to our Original Proposal and from the AER's Preliminary Determination, that most of the (limited number of) negative comments and assertions were aimed at the progressive, but quite limited, WTP research, not at the broader CEP. In

[29] AER, Preliminary Decision: *SA Power Networks determination 2015-16-2019-20*, April 2015, Overview, page 6-56

addition, the only independent assessment that was carried out on behalf of the AER was the limited Oakley Greenwood review, and that was confined solely to the WTP research.

The AER somehow appears to have concluded that SA Power Networks' CEP as a whole did not support the consumer supported / driven initiatives that were put forward in our Original Proposal because of:

- unsubstantiated, or technically lacking, stakeholder claims and assertions about the WTP research that were accepted by the AER; and
- the Oakley Greenwood review, the findings of which were misinterpreted by the AER, and then taken as evidence that the CEP as a whole was deficient when the review was, in fact, solely focussed on the WTP research only.

SA Power Networks contends that such a conclusion is manifestly incorrect and has ignored the substantive evidence provided on these customer concerns raised during the CEP and incorporated into the expenditure forecasts in the Original Proposal.

The NER require the AER to take into account the extent to which our proposed expenditure addresses the concerns of electricity consumers as identified by us in the course of our engagement with such consumers. The AER's incorrect conclusions about our consumer engagement have led it to reject the consumer supported / driven initiatives set out in our Original Proposal. That must now be reassessed, and appropriately addressed, by the AER.

3.4.5 Application of the rule requirements

As mentioned above, following the AEMC Rule change process in 2012, the NER were amended to give added focus to promoting the long term interests of consumers. This included the addition of a new expenditure factor requiring the AER, when assessing whether expenditure reflects the criteria under clauses 6.5.6 (c) and 6.5.7(c) of the NER, to have regard to

> *'the extent to which the forecast includes expenditure to address the concerns of electricity consumers identified by the DNSP in the course of its engagement with electricity consumers'* (**Consumer Engagement Factor**).

The requirement on the AER to 'have regard' to a factor means that the AER must treat that factor as a fundamental element of its decision.[30] The AER cannot simply note that such concerns have been identified and discard them.[31] It must treat the consideration of these concerns (and the extent to which forecast expenditure addresses them) as a central element of its decision.[32]

In promulgating the Consumer Engagement Factor, the AEMC stated that:

> *'Finally, a factor was added that requires the AER to have regard to the extent to which NSPs have considered what consumers seek. NSPs should be engaging with consumers in preparing their regulatory proposals and should factor in the needs and concerns of consumers in determining, for example, their capex programs.*
>
> *What consumers want and are prepared to pay for, whether in terms of reliability or some other element, will assist in showing what is efficient. The more confident*

[30] R Hunt; ex parte Sean Investments Pty Ltd [1979] 180 CLR 332 at 329; R v Toohey; ex parte Meneling Station Pty Ltd [1982] HCA 69, per Gibbs CJ at [5], per Mason J at [13]; Re Michael; ex parte Epic Energy (WA) Nominees Pty Ltd [2002] WASCA 231 at [55]; Telstra Corporation Limited v ACCC [2008] FCA 1758 at [105]; Telstra Corporation Limited v Australian Competition Tribunal [2009] FCAFC 23 at [267]; Re Application by EnergyAustralia [2009] ACompT 7 at [16]
[31] East Australian Pipeline Pty Ltd v ACCC [2007] HCA 44 at [52]
[32] Telstra v ACCC [2008] FCA 1758 at [52]

the AER can be that consumer's concerns have been taken into account, the more likely the AER could be satisfied that a proposal reflects efficient costs.'[33]

This, coupled with the fact that the NER were specifically amended to require the AER to have regard to this additional Consumer Engagement Factor, means that significant weight should be given to it by the AER.

As set out in the Original Proposal, and again in this Revised Proposal, SA Power Networks has, through our CEP, engaged with consumers to identify their expectations and concerns (or in the words of the AEMC, what they want and what they are prepared to pay for) and then integrated those expectations and concerns into our planning for the 2015-20 RCP and the expenditure forecasts in our regulatory proposal. The AER can therefore be confident that those concerns have been taken into account and be satisfied that our proposals reflect efficient costs.

Consumers' concerns must, of course, relate to the expenditure objectives in order for a DNSP to be entitled to include proposed expenditure in its building block proposal.

The 'customer supported/driven' programs set out in this Revised Proposal do relate to the expenditure objectives, namely the second, third and fourth objectives, for the reasons set out after the next paragraph.

Before turning to the objectives, it is imperative that SA Power Networks draws specific attention to a particular statement made by the AER in its Preliminary Determination. In the capital expenditure attachment to the Preliminary Determination, the AER makes the following statement:

> *'On the information available to us …we have been unable to identify the extent to which SA Power Networks' proposed total forecast capex includes capex that address the concerns of its consumers that it has identified.'*[34]

We do not support this statement, given that even the most cursory of examinations of the content of Chapters 9 through 16 of the Original Proposal (and numerous other components of that document), shows that the Original Proposal spoke at some length about the significant CEP feedback obtained by SA Power Networks and how we had then addressed that feedback in a variety of our capital (and operating) expenditure forecasts. See Table 3.1 in Section 3.2 above for a summary of the expenditure areas.

Second objective – applicable regulatory obligations or requirements

SA Power Networks' building block proposal must include expenditure to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.

These regulatory obligations or requirements include the requirements under the NER and a number of State based regulatory obligations. The obligations that are particularly relevant to the expenditure driven by SA Power Networks' consumers include:

- section 60(1) of the *Electricity Act 1996 (SA)* that requires us to take all reasonable steps to ensure that our electricity infrastructure is safe and safely operated; and
- clause 5.2.1(a) of the NER that provides that we have a duty to maintain and operate our distribution system in accordance with good electricity industry practice.

---

[33] AEMC, Economic Regulation of network Service Providers, Final Rule Determination, 29 November 2012, page 101
[34] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-31

These obligations require us to have regard to what a reasonable and prudent electricity distribution system operator faced with the same conditions and circumstances would do to ensure our distribution system is safe and safely operated and is maintained and operated in a manner that is consistent with the degree of skill, diligence, prudence and foresight expected from Australian electricity distribution system operators.

The safety standards arising from these obligations are required to be objectively determined. This means that what amounts to being 'safe' in the context of both section 60(1) of the *Electricity Act 1996 (SA)* and clause 5.2.1(a) of the NER, is informed and influenced by customer and community expectations which change over time.

Given that our CEP covered all customer segments and key stakeholder groups across our distribution network, it was representative of our customers and the South Australian community and demonstrates what they expect at this point in time. Our CEP has demonstrated that consumers value safety very highly and want (and expect) us to undertake additional steps and programs of work to ensure ongoing community safety. This includes (without limitation) mitigating the rising risks of bushfire ignition in South Australia by electricity infrastructure and managing the risks from older deteriorating infrastructure.

The fact that our CEP was unquestionably reflective of electricity consumers in South Australia and clearly demonstrates that their concerns about safety are very high means that, in our view, what amounts to being 'safe' continues to evolve. The change in this standard therefore requires additional actions to be taken by us and warrants additional expenditure being incurred.

These concerns have been integrated into the programs referenced in Tables 3.2 and 3.3 at the end of this chapter which form part of our Revised Proposal.

Fourth objective – maintaining safety

SA Power Networks' building block proposal must include expenditure to maintain the safety of the distribution system through the supply of standard control services.

As recognised by the AEMC in the 2013 Rule change relating to the expenditure objectives, what amounts to 'maintaining safety' under the fourth objective should not be limited to requirements arising from regulatory obligations or requirements associated with the provision of standard control services:

> *'Current levels of safety may appropriately have been influenced by safety standards in voluntary industry codes or Australian standards in addition to regulated standards. It would therefore not be appropriate to limit the expenditure allowance to the regulated standards for safety rather than the current obligation to maintain safety. Doing so could risk inadvertently reducing the level of safety delivered by NSPs.'*[35]

This means that 'maintaining safety' is to be interpreted to include safety issues that are not directly related to the operation of distribution networks, such as public safety issues.[36]

Regardless of whether SA Power Networks incurs expenditure to maintain safety to comply with applicable regulatory obligations or requirements or other public safety issues, what amounts to

[35] AEMC 2012, *Network Service Provider Expenditure Objectives,* Final Rule Determination, 19 September 2013, page 10 – 11.
[36] AEMC 2012, *Economic Regulation of Network Service Providers,* Final Rule Determination, 19 September 2013, page 10-11.

'maintaining safety' is to be determined at a particular point in time and is informed and influenced by customer and community expectations which change and evolve over time. This interpretation is consistent with what amounts to being 'safe' in the context of section 60(1) of the *Electricty Act 1996* (SA) and clause 5.2.1(a) of the NER.

As has already been established, SA Power Networks' CEP is representative of customer and community expectations in South Australia and has demonstrated that consumers value safety <u>very highly</u> and want (and expect) us to undertake additional steps and programs of work to ensure ongoing community safety. This includes (without limitation) mitigating the rising risks of bushfire ignition in South Australia by electricity infrastructure and managing the risks from older deteriorating infrastructure.

The fact that our CEP was unquestionably reflective of electricity consumers in South Australia and clearly demonstrates that their concerns about safety are very high means that, in our view, what amounts to being 'safe' continues to evolve. The change in this standard therefore requires additional actions to be taken by us and warrants additional expenditure being incurred.

These concerns have been integrated into the programs referenced in Tables 3.2 and 3.3 at the end of this chapter which form part of our Revised Proposal.

Third objective – maintaining quality

SA Power Networks' building block proposal must include expenditure to maintain the quality of supply of standard control services (to the extent that there is no applicable regulatory obligation or requirement).

As recognised by the AEMC in the 2012 Rule change, addressing customer preferences for improved amenity can amount to maintaining the quality of supply and should be taken into account by the AER in having regard to the Consumer Engagement Factor:

> *'In respect of [the Consumer Engagement Factor] which will allow for the AER to have regard to the extent to which NSPs have considered what consumers seek, there are various ways this could be relevant. For example, it may be the case that a majority of affected consumers are unhappy with the visual impact of a proposed new line. If the NSP engages with consumers, it may decide that the best way to address the concerns of consumers would be to build the line underground, even if this is a more expensive option. <u>When the AER considers the NSP's overall capex proposal, it should take into account that the proposed option will provide a higher quality of service in line with consumers' preferences and willingness to pay, above less expensive options which fall below the level of service demanded by customers</u>. In general, a NSP that has engaged with consumers and taken into account what they seek could reasonably expect the AER to take a more favourable view of its proposal.'*[37] *[Emphasis added]*

In addition, the AEMC has recognised that what consumers want and are prepared to pay for assists in showing what is efficient and this may result in a program being warranted even if it is not the least cost option.[38]

In its Preliminary Determination, the AER stated that:

---

[37] AEMC 2012, *Economic Regulation of Network Service Providers*, Final Rule Determination, 29 November 2012, page 115
[38] Ibid, page 101

> *'Where there are no regulatory obligations, we determine funding that would maintain the reliability, safety and quality of supply. Improved amenity is not an objective we are directed to consider when determining SA Power Networks' funding requirements.*
>
> *The amenity of SA Power Networks' tree trimming practices is a broader policy issue that goes beyond our remit.'*[39]

Given the comments by the AEMC in the 2012 Rule change set out above, the AER has misinterpreted the third objective and has erred in rejecting our proposals, as expenditure to address concerns about amenity can and does fall within the reach of the third objective.

We recognise that the expenditure objective relating to maintaining the quality of supply was amended by the AEMC in the 2013 Rule change. However, in that Rule change, the AEMC did not appear to refer to questions of amenity in its description of quality. We are of the view that this means the AEMC did not intend to limit the inclusion of expenditure for amenity in forecasts being assessed under clauses 6.5.6 and 6.5.7 of the NER.

SA Power Networks' CEP is representative of our consumers and the community in South Australia and clearly demonstrates that our consumers want us to take steps to maintain the quality of the services they receive. In the context of the significant and persistent community concerns over the aesthetics of our assets and activities, this includes undertaking different and additional tree trimming practices to improve the visual amenity of vegetation around power lines.

This is also supported by our extensive consultation and research on tree trimming that has shown there is a willingness to pay for enhancing longer term vegetation management approaches across the State. (For further information in relation to our willingness to pay research and its findings, we refer to earlier sections of this chapter and to Attachments 6.8 and 16.6 to the Original Proposal.)

The robust findings of SA Power Networks' comprehensive CEP, including our targeted willingness to pay research findings, have been integrated into the programs set out in Tables 3.2 and 3.3 below which form part of our Revised Proposal.

[39] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-98.

Table 3.2: Capital expenditure for SA Power Networks' customer supported programs

Item	2015-20 RCP June 2015 $M	Reference
Maintain secure supply to targeted bushfire safer places	26.8	**Chapter 7, Section 7.7**
Hardening the network to improve reliability during major event days	17.3	**Chapter 7, Section 7.9**
Improving reliability to low reliability (worst performing) feeders	8.6	**Chapter 7, Section 7.9**
Improving reliability for remote communities (Hawker and Elliston)	2.4	**Chapter 7, Section 7.9**
Improving reliability using a micro-grid trial	2.9	**Chapter 7, Section 7.9**
Capex Total	**58.0**	

Table 3.3: Operating expenditure for SA Power Networks' customer supported programs

Item	2015-20 RCP June 2015 $M	Reference
Demand Side Participation	**10.2**	**Chapter 8, Section 8.17**
Distribution network pricing	5.1	
Metering contestability	5.1	
Vegetation management	**33.2**	**Chapter 8, Section 8.23**
Shift in NBFRA cycle from 3 to 2 years	13.5	
NBFRA tree removal and replacement	6.1	
BFRA tree removal and replacement	10.5	
Community engagement and consultation	1.9	
Engagement of Arborists	1.2	
Customer Services	**4.3**	**Chapter 8, Section 8.24**
Customer education and consultation	1.7	
Self-service products	1.0	
Customer service team	1.6	
Community Safety	**5.4**	**Chapter 8, Section 8.25**
Bushfire communications	2.6	
Extreme weather	1.9	
Farmers and sailors	0.9	
Opex Total	**53.1**	

3.5 Revised Proposal

SA Power Networks' Revised Proposal includes forecast capital expenditure and operating expenditure to address the concerns of our consumers. These expenditures are set out in Tables 3.2 and 3.3 above and are explained in further detail in the referenced sections of this Revised Proposal.

Page left blank intentionally

4. Classification of services and negotiating framework

4.1 Rule requirements

Clause 6.12.1 of the NER requires the AER to make a number of constituent decisions as part of a distribution determination. The decisions relevant to the classification of SA Power Networks' services, and the negotiating framework to apply to SA Power Networks' negotiated distribution services during the 2015-20 RCP are as follows:

- Clause 6.12.1(1) requires the AER to make a decision on the classification of services to be provided by SA Power Networks during the course of the 2015-20 RCP;
- Clause 6.12.1(15) requires the AER to make a decision on the negotiating framework that is to apply to SA Power Networks for the 2015-20 RCP; and
- Clause 6.12.1(16) requires the AER to make a decision concerning the Negotiated Distribution Service Criteria (**NDSC**) for SA Power Networks.

4.2 SA Power Networks' Original Proposal

4.2.1 Classification of services

In Chapter 18 of our Original Proposal we proposed that in accordance with the NER, our distribution services for the 2015-20 RCP be classified as direct control services, negotiated distribution services (**NDS**) or unregulated services. Our direct control services were further classified as either standard control services (**SCS**) or alternative control services (**ACS**).

SA Power Networks adopted the AER's proposed classification for SCS and ACS, as laid out by the AER in its Framework and Approach Paper (**F&A**).[40] This proposed classification largely retained the existing classification of SA Power Networks' distribution and metering services for the 2010-15 RCP with the following exceptions:

- the classification of all Type 6 metering related services other than metering investigations and meter reading requested by customers would move from SCS to ACS; and
- all Type 5 metering related services other than metering investigations and meter reading requested by customers would move from NDS to ACS.

These changes were made in anticipation of Type 5 and Type 6 metering services becoming subject to competition during the 2015-20 RCP.

SA Power Networks proposed that meter exit and transfer fees be charged to recover our residual meter costs where a customer with an existing meter owned by SA Power Networks chose to move to another metering provider, unless an alternative approach could be agreed with the AER that would ensure SA Power Networks could be kept financially whole in relation to its previously mandated investment in these meters.

SA Power Networks also adopted the AER's proposed classification for NDS, but proposed that three additional services be explicitly defined in the NDS 'Other' category. These three services were:

[40] AER, *Final framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, April 2014.

- attendance at the customer's premises at the customer's or their agent's request to investigate a fault, where it is determined that the fault was not related to SA Power Networks' equipment or infrastructure;
- provision of relevant regional energy consumption data to Local Government Councils; and
- third party funded network upgrades, enhancements or other improvements including 'make-ready' work for NBN Co.

4.2.2 Negotiating framework and negotiated distribution service criteria

In Section 18.5 of our Original Proposal, along with Attachment 18.1 to the Original Proposal, we set out the negotiating framework that we proposed to apply during the 2015-20 RCP when negotiating with a person wishing to receive a NDS. That framework was substantively the same as the framework applying in the 2010-15 RCP but with modifications to reflect changes in relevant regulatory arrangements and to improve the functionality of the document and its administration.

SA Power Networks did not propose any changes to the NDSC. However, in response to further queries from the AER,[41] SA Power Networks proposed some minor wording changes to the NDSC in January 2015. This included replacing the word 'costs' with 'economic costs' throughout the NDSC to provide certainty and clarity to negotiating parties in relation to the meaning of the word 'costs'. The uncertainty surrounding the proper interpretation of the word 'costs' has already led to protracted negotiations in one instance and a formal dispute resolution process being commenced in relation to our NDS.

4.3 AER's Preliminary Determination

4.3.1 Classification of services

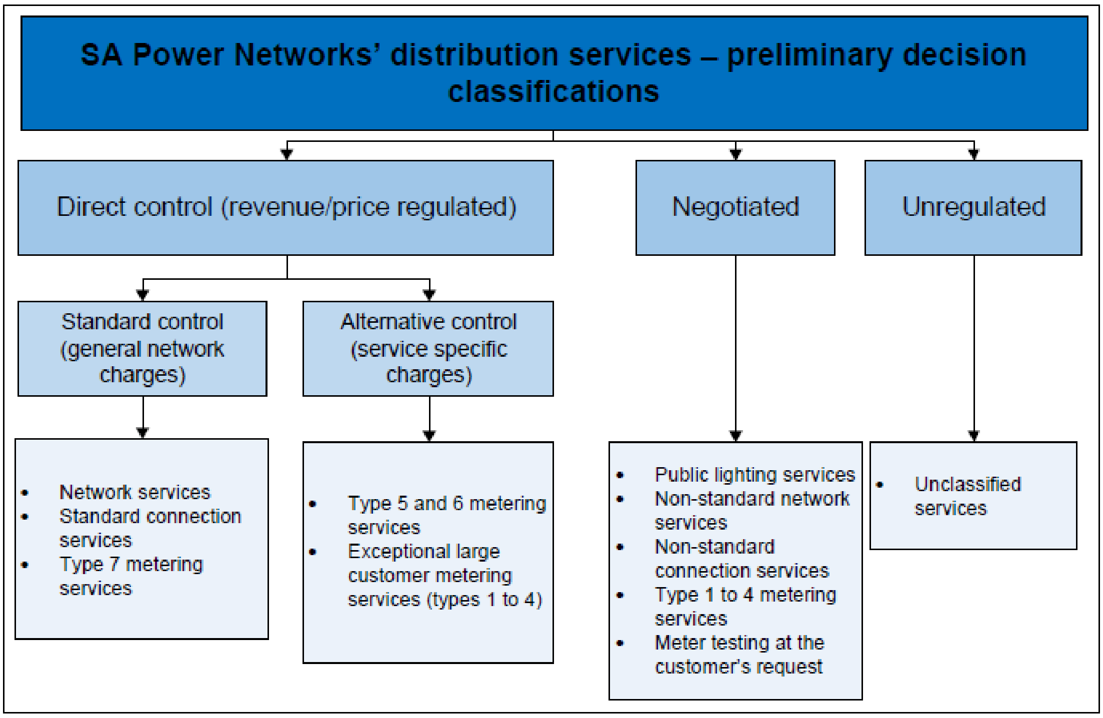
In its Preliminary Determination, the AER retained the service classification structure set out in its F&A except for the following:

- the AER classified separate Type 5 or 6 metering services for:
  - meter reading and maintenance;
  - meter provision before 1 July 2015; and
  - meter provision after 1 July 2015;
- the AER rejected SA Power Networks proposed exit fees for Type 6 current transformer connected meters and Type 1-4 exceptional meters and so did not classify those proposed services; and
- the AER accepted the three non-standard network services as NDS, as proposed by SA Power Networks.

Figure 4.1 sets out the AER's decision on the classification of SA Power Networks' services for the 2015-20 RCP.

[41] AER, *Call for submissions Proposed negotiated distribution service criteria for Energex, Ergon Energy and SA Power Networks-regulatory control period commencing 1 July 2015*, November 2014.

Figure 4.1: SA Power Networks' distribution services classifications for 2015-20 RCP



Source: AER, Preliminary Decision SA Power Networks determination 2015-16 to 2019-20, Attachment 13 Classification of Services, page 13-7

The AER rejected SA Power Networks' proposed meter exit and transfer fees because it was of the view that exit fees are a barrier to the development of effective competition in the provision of metering services as they deter customers from switching to another meter provider.

Instead, to ensure SA Power Networks could recover residual meter and transaction costs, the AER has instigated an annual metering charge that consists of two components:

- a **capital component** – designed to recover the residual costs associated with existing Type 5 and Type 6 meters; and
- a **non-capital component** – designed to recover ongoing operating costs associated with reading and maintaining meters.

The capital component will be chargeable to all customers with a regulated meter connected to SA Power Networks' distribution system as at 1 July 2015 and will continue to be charged to those customers whether or not they retain a regulated meter during the 2015-20 RCP.

The non-capital component will only be recovered from customers who retain an SA Power Networks' regulated meter during the 2015-20 RCP. If an existing customer switches to another metering provider, they will not be charged the non-capital component of the annual metering charge.

New customers, who connect to SA Power Networks' distribution system after 1 July 2015, will be provided with an SA Power Networks regulated meter but will be required to pay for their meter up front in lieu of incurring any ongoing capital metering charges. If these customers later select another metering provider, they will not incur any annual metering charges from SA Power Networks.

4.3.2 Negotiating framework and negotiated distribution service criteria

In its Preliminary Determination, the AER largely accepted SA Power Networks' proposed negotiating framework. However, to avoid any confusion it replaced the word 'classification' with the word 'category' in Section 3 and Schedule 1.

The AER also retained the existing NDSC but in doing so rejected SA Power Networks' proposed replacement of the word 'costs' with 'economic costs' throughout the NDSC because it was of the view that this would be unlikely to prevent future disputes and was a departure from the NER.

4.4 SA Power Networks' response to AER Preliminary Determination

4.4.1 Classification of services

SA Power Networks accepts the AER's classification of services for the 2015-20 RCP including the decisions to:

- regulate all Type 5 and 6 metering services as ACS which has required:
  - relevant costs associated with Type 6 energy data services, non-chargeable unscheduled meter reading and metering investigations to move from SCS to ACS; and
  - relevant costs associated with Type 5 metering services to move from NDS to ACS;
- implement new annual metering charges from 1 July 2015 comprising a capital component and a non-capital component, the levying of which will be dependent on whether or not the customer has an SA Power Networks regulated meter before or after 1 July 2015. However, as noted later in Section 17.1.4 of this Revised Proposal, we do not accept the AER's cost allocation between the two components;
- that new meters installed after 1 July 2015 will be charged for up front and that no capital component will be added to the metering asset base (**MAB**);
- the decision to separately classify Type 5 or 6 metering services as necessitated by the differentiated metering provision services before and after 1 July 2015, including:
  - meter reading and maintenance;
  - meter provision before 1 July 2015; and
  - meter provision after 1 July 2015;
- not classify any meter exit fees. This does not prevent SA Power Networks from charging exit fees to the relatively few large customers who have Type 6 or 'non-exceptional' Type 1-4 metering. The meter provision services to these customers are NDS and the ability to charge an exit fee, should one of these large customers move to another metering provider, ensures that residual costs are recovered from that customer; and
- accept SA Power Networks' proposal to classify three new non-standard network services proposed as 'Other' NDS. This decision clarifies that SA Power Networks can recover the costs for these services from the customers receiving them.

4.4.2 Negotiating framework and negotiated distribution service criteria

SA Power Networks accepts the minor modifications made by the AER to the negotiating framework, including the replacing of the word 'classification' in Section 3 and Schedule 1 of the proposed framework with the word 'category'.

SA Power Networks accepts the decision not to use the term 'economic costs' in place of 'costs' at various places in the NDSC.

4.5 Revised Proposal

4.5.1 Classification of services

SA Power Networks accepts the AER's classification of services for the 2015-20 RCP and does not propose any changes to the classification of services in our Revised Proposal. However as noted later in Section 17.1.4 of the Revised Proposal we do not accept the AER's cost allocation between the capital and non-capital components of the new annual metering charge.

4.5.2 Negotiating framework and negotiated distribution service criteria

SA Power Networks does not, in this Revised Proposal, propose that any changes be made to the negotiating framework as varied by the AER in its Preliminary Determination. SA Power Networks will amend the negotiating framework accordingly, and publish and apply the framework on that basis.

SA Power Networks also accepts and submits as part of its Revised Proposal the AER's decision to retain the existing NDSC.

Page left blank intentionally

5. Control mechanisms – Standard Control Services

5.1 Rule requirements

Clause 6.12.1 of the NER requires the AER to make a number of constituent decisions as part of a distribution determination. The decisions relevant to the control mechanism to apply to SA Power Networks' standard control services (**SCS**) during the 2015-20 RCP are as follows:

- Clause 6.12.1(11) requires the AER to make a decision on the form of the control mechanisms (including the X factor) for SCS (to be in accordance with the Framework and Approach paper (**F&A**)) and the formulae that give effect to those control mechanisms;
- Clause 6.12.1(13) requires the AER to make a decision on how compliance with a relevant control mechanism is to be demonstrated;
- Clause 6.12.1(17) requires the AER to make a decision on the procedures for assigning customers to tariff classes, or reassigning customers from one tariff class to another; and
- Clauses 6.12.1(19) and (20) require the AER to make a decision on how SA Power Networks is to report to the AER on its recovery of designated pricing proposal charges[42] and jurisdictional scheme amounts for each regulatory year of the 2015-20 RCP and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges.

5.2 SA Power Networks' Original Proposal

In Section 19.1 of our Original Proposal, consistent with the AER's binding decision in the F&A, we applied a revenue cap form of control to our SCS for the 2015-20 RCP.

Under a revenue cap form of control, the AER sets the total allowed revenue for each regulatory year of the 2015-20 RCP. SA Power Networks is then required to comply with the revenue cap by forecasting sales for the next regulatory year and setting prices so the expected revenue is equal to or less than the total revenue allowed. At the end of each regulatory year, SA Power Networks will report actual revenue to the AER and any over or under recovery is deducted from or added to the total revenue in future regulatory years.

Annual allowances will also be adjusted for outcomes from the various incentives schemes and incorporate any approved pass through events.

SA Power Networks also noted that transmission costs and costs associated with the South Australian photo-voltaic (**PV**) feed-in-tariff (**FiT**) scheme operate outside the SCS revenue cap arrangements. These costs are passed through to SA Power Networks and then to electricity customers by including these amounts in our network prices as tariff elements separate to the revenue cap elements.

5.3 AER's Preliminary Determination

In Attachment 14 to its Preliminary Determination, the AER stated that:

- the control mechanism for SA Power Networks' SCS for the 2015-20 RCP is a revenue cap;

[42] Designated pricing proposal charges recover all transmission costs incurred by SA Power Networks' customers and are paid by SA Power Networks to ElectraNet SA.

- the revenue cap for any given regulatory year is the total annual revenue allowed for distribution services for that regulatory year plus any adjustment required to move a 'DUoS under/over account' to zero;
- price movements in each SA Power Networks' tariff class will be constrained in accordance with a pre-determined formula (set out in Figure 14.2);
- SA Power Networks must maintain a 'DUoS unders and overs account' in its annual pricing proposal (which is prepared and lodged in accordance with clause 6.18.2 of the NER) in the form set out in Appendix A;
- as part of its annual pricing proposal, SA Power Networks must submit a record of the amount of revenue recovered from designated pricing proposal charges and associated payments in accordance with Appendix B;
- SA Power Networks must report its jurisdictional scheme amounts (being the solar PV FiT scheme amounts) recovery in accordance with Appendix C; and
- in assigning retail customers to tariff classes, SA Power Networks must apply the procedures set out in Appendix D.

The AER's Preliminary Determination Overview document and Attachment 14 to that document set out the AER's decision with respect to the control mechanism that will apply to SA Power Networks' SCS.

The revenue control formula and side constraint pricing formula both contain:

- an 'I' factor, to incorporate a final carry-over amount for the Demand Management Incentive Scheme applying in the 2010-15 RCP;
- an 'S' factor, to incorporate annual adjustments for financial rewards/penalties associated with the Service Target Performance Incentive Scheme (**STPIS**);
- an 'X' factor, which smooths annual revenue allowances in accordance with an average price path. The AER has already decided the X factors which will apply for the 2015-20 RCP. However, consistent with how the AER has decided to calculate the allowed weighted average cost of capital, these X factors will be adjusted each year to account for annual return on debt updates. This adjusts the allowed rate of return component of the revenue building blocks each regulatory year; and
- a 'C' factor, which will recover any pass through amounts approved in the 2015-20 RCP.

Actual revenue recovered will vary to the extent that actual demand and consumption quantities vary from forecast amounts. Under the revenue cap arrangements, this variance will be accounted for in the DUoS unders and overs account. A 'DUoS' factor in the side constraint pricing formula incorporates this mechanism.

The pricing side constraint limits the annual increase in average revenue from any individual tariff class to the greater of CPI-X+2% or CPI+2%. The annual I, C and DUoS factor adjustments are excluded from the application of this side constraint.

In the 2010-15 RCP, a jurisdictional derogation applied an additional side constraint which was that the fixed supply charge component of small customer tariffs could increase by no more than $10 per annum. This derogation will lapse for the 2015-20 RCP as the AER has decided not to apply this side constraint for that RCP.

5.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks accepts the AER's decision to regulate SCS under a revenue cap arrangement. We note the revenue control formula and the side constraint pricing formula as set out in Figures 14.1 and 14.2 respectively. However, while the intent and obligations are clear, the revenue cap formula in Figure 14.1 should include an explicit 'DUoS' factor. This factor is not relevant to SA Power Networks in the first regulatory year of the 2015-20 RCP but will be relevant in later regulatory years. For this reason, the formula in Figure 14.1 should be adjusted.

SA Power Networks also accepts the requirements to:

- maintain a 'DUoS under/over account' in our annual pricing proposal as set out in Appendix A;
- maintain an unders and overs account for designated pricing proposal charges in our annual pricing proposal as set out in Appendix B;
- maintain a jurisdictional scheme unders and overs account in our annual pricing proposal as set out in Appendix C; and
- assign retail customers to tariff classes in accordance with the procedures in Appendix D.

SA Power Networks further accepts the AER's decision to not apply the $10 per annum side constraint to the fixed supply charge of small customer tariffs in the 2015-20 RCP.

5.5 Revised Proposal

Our Revised Proposal applies the control mechanisms decisions that form part of the Preliminary Determination, subject to the revenue control formula being amended to include the DUoS factor as follows:

$$TAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{i\,j} q_t^{i\,j}$$

Where:

i = 1, 2, …n and j = 1, 2, ...m

t =1, 2,…5

$$TAR_t = AR_t \pm I_t \pm C_t \pm DUoS_t$$

$AR_t = AR_{t-1}(1 + \Delta CPI_t)(1 - X_t)(1 + S_t)$; and

$DUoS_t$ is an annual adjustment factor related to the balance of the DUoS unders and overs account with respect to regulatory year t.

SA Power Networks' annual pricing proposals to the AER will demonstrate compliance with the requirements set out above.

Page left blank intentionally

6. Peak demand and sales forecasts

6.1 Rule requirements

The NER do not specifically refer to forecasting sales and demand, except to the extent that the forecast influences forecast operating and capital expenditure:

- clause 6.5.6(c) of the NER requires the AER to accept the forecast of required operating expenditure proposed by SA Power Networks if the AER is satisfied that, among other things, the forecast operating expenditure reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives; and
- similarly, clause 6.5.7(c) of the NER requires the AER to accept the forecast of required capital expenditure proposed by SA Power Networks if the AER is satisfied that, among other things, the forecast capital expenditure reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

To the extent that SA Power Networks is required to provide indicative price outcomes as shown in Chapter 16 of this Revised Proposal, we must also prepare a reasonable estimate of energy forecasts for key customer groupings.

This chapter discusses global demand (which is the single diversified demand projection across the entire distribution network) and spatial demand (which includes localised demands on each part of the distribution network). Network costs are driven by spatial demand whereas South Australian generation requirements are driven by global demand. The spatial demand forecasts are prepared by distribution network planners and the global demand forecasts (and energy forecasts) are prepared by market planners such as the Australian Energy Market Operator (**AEMO**).

6.2 SA Power Networks' Original Proposal

Section 12.1 of SA Power Networks' Original Proposal outlined our approach to forecasting sales and demand at the system level for the 2015-20 RCP. Essentially, we:

- adopted the medium growth outlook of 10 per cent Probability of Exceedance (**PoE**) peak demand projections for South Australia from AEMO's National Energy Forecast Report (**NEFR**) for 2014; and
- translated these forecasts into sales forecasts for SA Power Networks by:
  - reducing AEMO's forecast to account for distribution losses;
  - utilising AEMO's high future growth case for solar photo-voltaic (**PV**) generation as it more closely matched the level of solar PV generation seen since the Solar PV Feed-in Tariff (**FiT**) scheme closed; and
  - adding back the level of solar PV energy exported to the network (as AEMO forecasts assume all solar energy is used in-house) to match the solar PV output to the peak time experienced by our network.

This resulted in a flat outlook for SA Power Networks' global demand and energy sales to 2020. SA Power Networks also separately forecast sales to major business customers, as this customer segment is not separately identified in AEMO's forecasts.

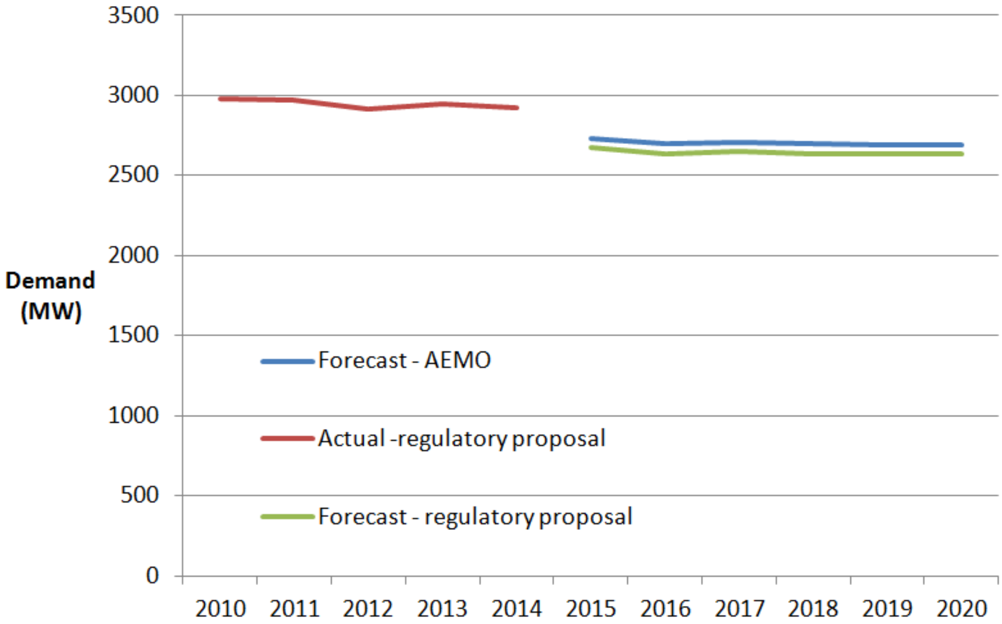
Our Original Proposal also noted that while 'global' demand growth is forecast to be flat, localised economic and demographic changes drive localised demand increases in some areas of our network.

6.3 AER's Preliminary Determination

Appendix C in Attachment 6 to the AER's Preliminary Determination, discusses forecast demand in SA Power Networks' network for the 2015-20 RCP. The AER was satisfied that SA Power Networks' Original Proposal reasonably reflects a realistic expectation of demand.

The AER noted that maximum demand will 'flatten' over the 2015-20 RCP and that AEMO also forecast a similar flattening of demand growth for SA Power Networks' network. AEMO's 2014 NEFR demand forecast is 3 per cent higher than SA Power Networks' demand forecast over a 10 year period. The slight difference in forecasts was due to different forecasting inputs used by AEMO and SA Power Networks. The key differences were the selection of forecasting starting points, the assessment of energy efficiency and solar PV generation. The forecasts are compared in Figure 6.1 below.

Figure 6.1: Original Proposal - SA Power Networks' and AEMO's global demand forecasts for summer



Source: AER's Preliminary Determination, Attachment 6 – Capital Expenditure, Page 6-140

The AER noted that AEMO's December 2014 'Transmission Connection Point Forecasting Report for South Australia' showed that SA Power Networks started its system demand forecasts from the most recent historical point and adopted a consistent forecasting methodology to AEMO.

The AER also noted that submissions from Origin Energy and AGL acknowledged that SA Power Networks' forecasts were reasonable because they were similar to AEMO's demand forecasts and reflected a reasonable expectation of demand for the 2015-20 RCP.

In Section B.2.1 of Appendix B in Attachment 6 to the AER's Preliminary Determination, the AER considered that SA Power Networks' projected doubling of solar panel connections by 2020 may be overstated by 30 per cent when compared with AEMO's independent forecast of South Australian solar PV generation by 2020, which forecast an increase in solar PV generation of 70 per cent by 2020. The AER noted that AEMO is currently preparing updated solar PV generation forecasts as part of its NEFR for 2015 and that SA Power Networks should take these into account when preparing this Revised Proposal.

6.4 SA Power Networks' response to AER Preliminary Determination

In its Preliminary Determination, the AER did not raise any issues in relation to our sales and demand forecast, apart from the point noted on the possible rate of increase in solar PV generation. The AEMO 2015 NEFR provides further information on this matter. The 2015 NEFR was released by AEMO on 18 June 2015 and has been used to update this Revised Proposal.

6.5 Revised Proposal

SA Power Networks has updated the spatial demand forecast using recent actual demands including those from the 2014/15 Summer. As the Summer was generally mild apart from a heatwave just after New Year, limited useful additional planning information was available. The 2015 spatial forecast is largely unchanged from that produced in 2014 for the Original Proposal.

The AEMO 2015 NEFR has had four major areas of change which we need to consider in our Revised Proposal:

1) the South Australian economy and population is expected to grow albeit at a slower rate than the national economy. This growth will offset much of the energy efficiency impacts on forecast energy and demands;
2) the price reductions associated with carbon tax removal and network price reduction is expected to have a price elasticity effect, with sales increasing over the next two regulatory years;
3) installation of solar PV systems in residential areas is expected to continue, supplemented by a step change in installations by businesses for solar PV systems up to 100 kW; and
4) the outlook for minimum demands in South Australia is concerning. On sunny days in late Spring with mild temperatures, we can expect to see the demand for electricity near midday to continue to decline (SA Power Networks already has negative loads on the residential network at this time. AEMO has reported that the PV output can already exceed the demand of small customers (residential and business) using Type 6 meters, as evidenced by the net system load profile showing negative load in late 2014). The AEMO 2015 NEFR shows that at current forecasts (and presuming that no corrective action and/or battery installation occurs), the 2023/24 South Australian minimum demand near midday will be entirely supplied by solar PV generation displacing all wind and thermal generation.

We have compared our 2015 spatial forecast with our global forecast. We have also compared our global forecast with the AEMO 2015 NEFR demand forecast. This is the same approach as we used with the Original Proposal. We have found that, as with the Original Proposal, these three Revised Proposal demand forecasts are well aligned.

We have also updated our sales forecasts to align with the AEMO 2015 NEFR using the same approach as in the Original Proposal. That is we have:

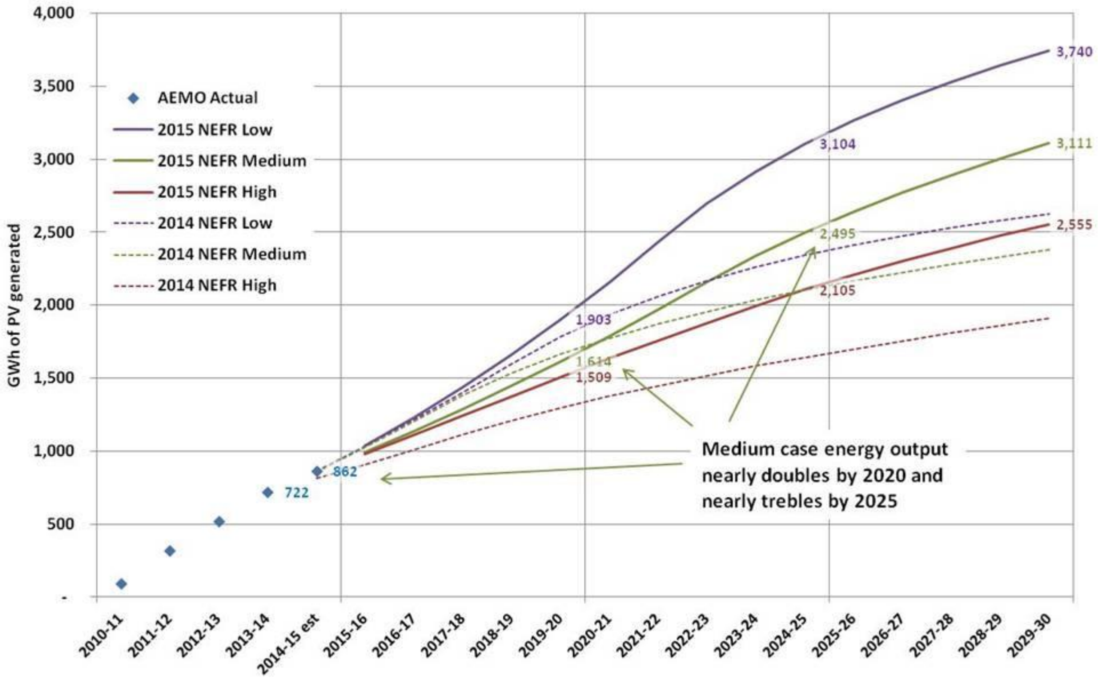
- adopted the AEMO medium growth outlook of 10 per cent PoE forecast peak demand projections for South Australia from the AEMO 2015 NEFR; and
- translated these forecasts into sales forecasts for SA Power Networks by:
  - reducing AEMO's forecast to account for distribution losses;
  - utilising AEMO's high future growth case for solar PV energy as it more closely matched the level of solar seen since the Solar PV FiT scheme closed; and

– adding back the level of solar PV energy exported to the grid (as AEMO forecasts assume all Solar energy is used in-house) to match the solar PV energy output to the peak time experienced by our network.

The AEMO medium growth forecast for solar PV energy suggests a continuation of the average rate of installation over the last five years, with business customers installing significant quantities and residential customers continuing to install significant quantities at a faster rate than we have seen over the last two years since the solar PV FiT schemes have closed. A comparison of the AEMO 2015 NEFR gross solar PV output forecasts is shown below in Figure 6.2.

The solar PV outlook coupled with the AEMO 2015 NEFR concern about future South Australian minimum demand levels reaching zero in 2023/24 all confirms the issues we have raised in our Original Proposal and in this Revised Proposal on two-way networks, including the work needed to ensure networks remain stable through this period of significant change.

Figure 6.2: AEMO 2015 NEFR forecasts of SA gross solar PV output (GWh)



Source: SA Power Networks 2015

As a result of AEMO's South Australia energy forecast being more optimistic in the 2015 NEFR than in the 2014 NEFR, we have amended the sales forecast as set out in Table 6.1. Total customer sales in 2019/20 are now forecast at 10,705 GWh. This is 2.6% higher than the Original Proposal forecast which was 10,430 GWh.

Table 6.1: SA Power Networks' sales forecasts for the 2015-20 RCP (GWh per annum)

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Customer Sales	9253	9275	9493	9544	9625	9705
Major Business	1030	1098	1050	1000	1000	1000
Total Sales	**10283**	**10372**	**10543**	**10544**	**10625**	**10705**
Growth per annum						
Customer sales		0.2%	2.4%	0.5%	0.8%	0.8%
Major Business		6.6%	-4.3%	-4.8%	0.0%	0.0%
Total Sales		**0.9%**	**1.6%**	**0.0%**	**0.8%**	**0.8%**

Page left blank intentionally

7. Forecast capital expenditure

In its Preliminary Determination, the AER did not accept SA Power Networks' proposed forecast capital expenditure for standard control services (**SCS**) of $2,481.0 (June 2015, $ million), excluding equity raising costs, because it was not satisfied that our proposed forecast capital expenditure reasonably reflected the capital expenditure criteria. The AER has determined a substitute estimate of $1,684.0 (2014-15, $ million) which represents a 32% reduction from SA Power Networks' proposed capital expenditure forecast.

In this chapter of our Revised Proposal, we explain our revised capital expenditure forecast of $2,070.8 (June 2015, $ million), excluding equity raising costs, for the 2015–20 RCP. SA Power Networks has prepared this revised forecast taking into consideration the AER's Preliminary Determination, public submissions on our Original Proposal and further refinement of our program criteria and forecasting methodologies.

7.1 Rule requirements

Clauses 6.8.2(c)(2) and 6.5.7(a) of the NER require SA Power Networks to submit a building block proposal for the total forecast capital expenditure for the 2015–20 RCP, that SA Power Networks considers is required in order to achieve the capital expenditure objectives.

The capital expenditure objectives are to:

1) meet or manage the expected demand for *SCS* over that period;
2) comply with all applicable regulatory obligations or requirements associated with the provision of *SCS*;
3) to the extent that there is no applicable regulatory obligation or requirement in relation to:
    a. the quality, reliability or security of supply of *SCS*; or
    b. the reliability or security of the *distribution system* through the supply of *SCS*

   to the relevant extent:

    a. maintain the quality, reliability and security of supply of *SCS*; and
    c. maintain the reliability and security of the *distribution system* through the supply of *SCS*; and
4) maintain the safety of the *distribution system* through the supply of *SCS*.

The AER **must** accept the capital expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the 2015–20 RCP reasonably reflects the capital expenditure criteria. In making this assessment the AER must have regard to the capital expenditure factors which include (but are not limited to) benchmarking, historical performance and, importantly, the extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified in the course of SA Power Network's engagement with electricity consumers.

The capital expenditure criteria are as follows:

1) the efficient cost of achieving the capital expenditure objectives;
2) the cost that a prudent operator would require to achieve the capital expenditure objectives; and

3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

7.2 SA Power Networks' Original Proposal

In our Original Proposal, we explained the reasons for the variation between the actual capital expenditure we incurred and the AER's capital expenditure allowance for the 2010-15 RCP. We also explained the processes, inputs and methodologies we used to develop our forecast capital expenditure for the 2015-20 RCP. These explanations have not been repeated in detail in this Revised Proposal, except where necessary to explain our revised capital expenditure forecast.

In its Original Proposal SA Power Networks forecast a total capital expenditure for SCS of $2,481.0[43] (June 2015, $ million) as summarised in Table 7.1. This excludes $4.5 million of equity raising costs which are separately calculated in the Post Tax Revenue Model (**PTRM**).

Table 7.1: Original Proposal SCS Forecast net capital expenditure for the 2015-20 RCP (June 2015, $ million)

Standard Control Services	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Replacement	134.0	155.9	166.0	169.2	166.9	**792.0**
Augmentation	146.1	184.7	195.9	185.6	171.7	**884.0**
Connections						
Customer connections (gross)	136.0	138.3	140.8	147.6	155.1	**718.0**
Customer contributions	(102.0)	(102.1)	(103.6)	(108.0)	(112.8)	**(528.5)**
Customer Connections (net)	34.0	36.3	37.2	39.7	42.3	**189.4**
Non Network	144.9	131.5	111.4	123.3	104.5	**615.6**
Total SCS expenditure forecast (net)	**459.1**	**508.3**	**510.4**	**517.8**	**485.4**	**2,481.0**

Our forecast of total capital expenditure for SCS was designed to deliver an appropriate balance of investments to support optimal service provision for our customers in both the short and long term.

To ensure consistency with the National Electricity Objective (**NEO**) and the requirements of the NER, this balanced investment program took account of key operating environment factors, including:

- the need to comply with all applicable regulatory obligations and requirements, including those relating to safety (of the network infrastructure and its operation), service standards and asset management practices;

[43] SA Power Networks, *Regulatory Proposal 2015-20*, 30 October 2014, page 179.

- emerging changes in applicable regulatory obligations and requirements, including but not limited to, Power of Choice reform program developments, that reflect significant changes in how our distribution network will need to operate in the future;
- ongoing rapid connection rates of new customer technologies such as solar photo-voltaic (**PV**) panels; and
- ongoing changes in customers' expectations concerning the level of service we should be providing to them.

We have been proactive and thorough in addressing these factors including through our unprecedented efforts to capture and understand customer and stakeholder perspectives throughout the course of our consumer engagement program (**CEP**). Our CEP is discussed in Chapter 3 of this Revised Proposal.

Our Original Proposal also went to great lengths to explain how our capital (and operating) expenditure forecasts relate to the provision of SCS to our customers. This was achieved through a series of chapters (Chapters 9 to 16 in particular) which addressed the individual service areas, applicable regulatory obligations and requirements, current and emerging issues relevant to the area, CEP feedback, and how we addressed the CEP feedback in our forecasts. The chapters of the Original Proposal, and the key links to our capital expenditure forecasts, are shown in Table 7.2.

Table 7.2: How our Original Proposal addressed customer concerns

Original Proposal chapter	Key links to our capital expenditure forecasts
Chapter 9 'Keeping the power on for South Australians'	Network asset replacement, condition monitoring
Chapter 10 'Responding to severe weather events'	Network reliability, hardening the network
Chapter 11 'Safety for the community'	Bushfire risk mitigation, road safety
Chapter 12 'Growing the network in line with South Australia's needs'	Network augmentation, security, customer connections
Chapter 13 'Ensuring power supply meets voltage and quality standards'	Quality of supply maintenance, connection of new customer technologies
Chapter 14 'Serving customers now and in the future'	Systems supporting customer service and cost reflective tariffs
Chapter 15 'Fitting in with our streets and communities'	Power Line Environment Committee
Chapter 16 'Capabilities to meet our challenges'	Supporting IT systems, property and vehicle fleet investment

From an examination of the content of these chapters in the Original Proposal (and numerous other components of it), it is self-evident that our Original Proposal provided significant evidence in terms of how our capital (and operating) expenditure forecasts addressed the concerns of our customers.

7.3 AER's Preliminary Determination

In accordance with clause 6.5.7(d) of the NER, the AER has not accepted the total forecast capital expenditure proposed by SA Power Networks for the provision of SCS for the 2015–20 RCP, and has set out its reasons for this decision in its Preliminary Determination.

The AER's preliminary decision is that SA Power Networks' forecast capital expenditure for SCS of $2,481.0 (June 2015, $ million), excluding equity raising costs, for the 2015-20 RCP did not reasonably reflect the capital expenditure criteria. The AER determined a substitute estimate of $1,684.0 (June 2015, $ million) which it believed more reasonably reflects the capital expenditure criteria. Table 7.3 outlines the AER's preliminary decision compared to our Original Proposal.

Table 7.3: AER's preliminary decision on SA Power Networks' total capital expenditure forecast (June 2015, $ million)

Standard Control Services	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Original Proposal	459.1	508.3	510.4	517.8	485.4	2,481.0[44]
AER preliminary decision	311.2	341.7	348.3	345.0	337.8	1,684.0
Difference	-147.9	-166.6	-162.1	-172.8	-147.7	-797.0
% Difference	-32%	-33%	-32%	-33%	-30%	-32%

In its preliminary decision, the AER considered SA Power Networks did not have sufficient regard to top-down efficiency tests or delivery strategies and that its forecasts were overly risk averse, particularly in the areas of safety and reliability expenditure.

The key areas of difference between the AER's substitute estimate and our original capital expenditure proposal are as follows:

- the AER did not accept our proposed replacement capital expenditure forecast because the AER formed the view that we did not establish that our asset risk would increase by the amount forecast in the 2015-20 RCP;
- the AER did not accept our total augmentation capital expenditure forecast. In determining its substitute estimate the AER:
  - accepted our forecast demand growth, and expenditures related to maintaining network reliability and power quality, and increasing the security of supply to Kangaroo Island;
  - did not accept our bushfire mitigation program and did not accept our road safety program as it was of the view these programs did not reflect a prudent operator's efficient costs;
  - did not accept our proposal to improve reliability to our worst served customers in country regions as was of the view that it was not clear whether the Service Target Performance

[44] Excludes equity raising costs, SA Power Networks' Original Proposal forecast includes $4.5 million for equity raising costs. In its Preliminary Determination the AER removed equity raising costs from capital SCS.

Incentive Scheme (**STPIS**) regime would be a more appropriate source of funding for this program if the benefits of the program exceeded the cost; and

  – did not accept our low voltage network monitoring proposals as it was of the view that our forecast solar panel connections were overstated compared to AEMO's and therefore we could meet our service obligations without additional monitoring;

- the AER accepted our customer connections capital expenditure forecast as it was consistent with forecast construction activity in South Australia;
- the AER did not accept our non-network capital expenditure forecast as it had concerns regarding the deliverability of our IT program and for IT, fleet and property it was of the view the capital expenditure forecasts did not reflect the efficient costs of a prudent operator;
- the AER did not accept our forecast of capitalised overheads. The reduction in forecast overheads reflects the reduction in direct capital expenditure forecast that is expected to attract overhead expenditure; and
- the AER did not accept our real price escalations and applied the Deloitte Access Economics forecast of the Wages Price Index for the Electricity, Gas, Water and Waste Services industry sector to labour costs, and applied no real price escalation to materials costs.

The AER determined a substitute estimate of $1,684.0 (June 2015, $ million) for capital expenditure for SCS for the 2015-20 RCP, shown by driver in Table 7.4. Whilst the substitute estimate has been categorised into specific drivers (eg replacement), the AER's preliminary decision concerns SA Power Networks' total forecast capital expenditure.

Table 7.4: AER preliminary decision on SCS forecast net capital expenditure for the 2015-20 RCP (June 2015, $ million)

Standard Control Services	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Replacement	113.3	130.9	137.1	139.5	136.4	**657.1**
Augmentation	86.6	105.7	111.2	104.5	96.8	**504.7**
Connections						
Customer connections (gross)	136.0	138.3	140.8	147.6	155.1	**718.0**
Customer contributions	(102.0)	(102.1)	(103.6)	(108.0)	(112.8)	**(528.5)**
Customer Connections (net)	34.0	36.2	37.2	39.6	42.3	**189.4**
Non Network	81.8	74.6	70.7	70.1	72.3	**369.5**
Total SCS expenditure forecast (net)	**315.7**	**347.4**	**356.2**	**353.8**	**347.8**	**1,720.8**
Escalation adjustment	-4.5	-5.7	-7.7	-8.9	-10.0	**-36.8**
Total SCS expenditure forecast (net) adjusted	**311.2**	**341.7**	**348.3**	**345.0**	**337.8**	**1,684.0**

Note: Excludes equity raising costs. In its Preliminary Determination the AER removed equity raising costs from capital expenditure for SCS.

The following sections of this chapter describe SA Power Networks' revised capital expenditure forecasts for areas of the AER's Preliminary Determination that SA Power Networks considers must be amended in the AER's Final Determination.

7.4 Replacement

The AER did not accept our forecast replacement capital expenditure of $792.0 (June 2015, $ million). Instead, the AER included in its substitute estimate an amount of $657.1 (June 2015, $ million).

SA Power Networks notes that two adjustments need to be made to the Preliminary Determination. Table 7.5 summarised our Original Proposal replacement expenditure, the AER's Preliminary Determination and our Revised Proposal, discussed below.

Table 7.5: Replacement capital expenditure forecast summary (June 2015, $ million)

Replacement	Original Proposal	Preliminary Determination	Revised Proposal	Comment
Replacement	792.0	657.1	731.8	See below

Note: Excludes the AER materials escalation adjustment.
Slight variations between the Original Proposal, Preliminary Determination and the Revised Proposal occur, even when we accept the AER's preliminary decision, due to materials and labour escalation adjustments, refer to Section 7.22.

7.4.1 Rule requirements

Replacement expenditure is required to enable SA Power Networks to maintain an acceptable level of distribution system safety and reliability by addressing identified defects in, and the degradation of, our ageing network assets to meet our jurisdictional service standards and to comply with our other regulatory obligations and requirements.

The capital expenditure objectives which are most relevant to forecast replacement capital expenditure are:

- Clause 6.5.7(a)(2) of the NER – comply with all applicable *regulatory obligations or requirements* associated with the provision of SCS; and
- Clause 6.5.7(a)(4) of the NER – maintain the safety of the *distribution system* through the supply of SCS.

Our regulatory obligations and requirements relating to the provision of SCS and the maintenance of the safety of our distribution system derive from a number of sources. These sources include:

- section 60 of the *Electricity Act 1996* (SA);
- the requirements of our Distribution Licence;
- the Essential Services Commission of South Australia's (**ESCoSA**) approved Safety, Reliability, Maintenance and Technical Management Plan (**SRMTMP**);
- the various requirements relating to the maintenance of network assets referred to in the *Electricity (General) Regulations 2012* (SA) (and Section 12 of Schedules 1-4 in particular);
- the ESCoSA set service standards for reliability; and
- Chapter 5 of the NER (and clauses 5.2.1 and 5.2.3 in particular which require us to maintain and operate our facilities in accordance with relevant laws, the requirements of the Rules and good electricity industry practice, and the power system performance and quality of supply standards set out in Schedule 5.1 of the NER).

7.4.2 SA Power Networks' Original Proposal

In our Original Proposal, we forecast capital expenditure of $792.0 (June 2015, $ million) for our total asset replacement program. Our replacement expenditure relates to power lines, substations, telecommunications components of the network, and safety related programs.

In developing our forecast for the 2015–20 RCP, we sought to prudently manage the return of our asset portfolio risk to the level that is required for compliance with our regulatory obligations and requirements under the SRMTMP, as approved by ESCoSA on recommendation of the Office of the Technical Regulator (**OTR**). The primary reason for returning our risk profile to historical levels is our heightened concern that the structural failure of an asset could result in damage to people, property, the environment or our network. That is, limiting the potential for public safety risk (through direct impact or electric shock following structural failure which risk is more significant in densely populated urban areas) and for bushfire risk (asset failure causing fires particularly in Bushfire Risk Areas (**BFRA**s).

For our power line assets, we forecast a significant increase in capital expenditure to enable us to manage the forecast level of network asset defects while meeting our regulatory obligations and progressively moving network risks back to levels acceptable to SA Power Networks and the OTR. SA Power Networks considers this approach is prudent, delivers an efficient outcome over the longer term, and is required to discharge our duty to take reasonable steps to ensure that our distribution system is safe and safely operated in accordance with section 60(1) of the *Electricity Act 1996* (SA).

For our substation assets, we forecast capital expenditure that was, overall, consistent with our average historic expenditure.

In our Original Proposal, we also forecast replacement expenditure for telecommunications and general safety programs required to maintain an acceptable level of safety and reliability (by addressing the degradation of our ageing assets), to meet our jurisdictional service standards and to comply with our regulatory obligations and requirements.

7.4.3 AER's Preliminary Determination

In its Preliminary Determination, the AER did not accept our proposed capital expenditure forecast of $792.0 (June 2015, $ million), instead the AER included in its alternative estimate of total capital expenditure, an amount of $657.1 (June 2015, $ million, excluding escalations adjustment) on account of replacement capital expenditure.

The AER used its predictive (repex) modelling in conjunction with a technical review to assess approximately 77% of our proposed replacement expenditure. The six asset groups modelled were poles, overhead conductors, underground cables, service lines, transformers and switchgear. The remaining categories of expenditure, which include pole top structures and supervisory control and data acquisition equipment (**SCADA**), were not modelled in this way. Instead the AER used historical expenditure as a basis for its assessment.

The AER acknowledged that the change in our inspection practices has resulted in us identifying an increased number of defects and considered '*there is a reasonably well demonstrated backlog of defects that SA Power Networks could prudently seek to address…*'. Further the AER noted that its '*technical review has also led us to understand that defect volumes is an important factor that SA Power Networks' CBRM tool relies on in forecasting risk, and hence replacement volumes.*'[45]

---

[45] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 6-105.

The AER was of the view that our asset management strategies for replacement were reasonable for assessing and prioritising the replacement works for our 2015-20 RCP. However, it did not consider there was sufficient evidence to support our forecast replacement expenditure being prudent and efficient and therefore its alternative estimate for the six modelled asset groups was based on its repex modelling and not on our forecasts.

The AER noted we forecast $72 (June 2015, $ million - excluding overheads, including the balancing item adjustment) of replacement expenditure for pole top structures, representing a 36% increase compared to the 2010–15 RCP.

The AER undertook a technical review of the pole top forecast and concluded:

> *'we came to the view that SA Power Networks may have a backlog issue related to increased identification of condition-based issues with its power line assets. However, we did not consider SA Power Networks had justified the increase in expenditure from the last regulatory control period of the level it had proposed. In particular, it had not established a change in risk that would necessitate such a significant increase. Given this, we do not consider there is sufficient justification for a step increase in pole top structure repex in the 2015–20 regulatory control period.'*[46]

Taking the above into consideration, the AER based its alternative pole top estimate on our historic expenditure levels.

7.4.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks does not accept the AER's alternative forecast for our replacement capital expenditure forecast as we believe there are two matters in which the AER has erred in developing its substitute amount.

The six asset groups assessed through the AER's repex model

We understand the AER's rationale for substituting the replacement capital expenditure forecast produced by its repex model, which model assumes historical expenditure modified by historical asset lives is a good predictor of prudent future expenditure. However, we have reviewed the repex model scenario[47] and consider that the AER has made an arithmetic error in calculating the appropriate forecast from that model.

We consider that the AER has incorrectly used the forecast produced by the model. In its Preliminary Determination, the AER stated, *'In total for all six modelled categories we have included an amount of $487 million ($2014–15)* [excluding overheads] *in our alternative estimate of total forecast capex….'*.[48] However, SA Power Networks' analysis has identified this forecast was for the years 2014 to 2018. The forecast should have been based on the years 2015 to 2019, which amounts to $538.6 (June 2015, $ million - excluding overheads, including the balancing item adjustment).

Using the correct years results in a $51.1 (June 2015, $ million - excluding overheads, including the balancing item adjustment) increase to the amount approved in the AER's Preliminary Determination.

---

[46] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 6-106.
[47] AER*, Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20,* April 2015, Repex model (calibrated lives – historical unit costs).
[48] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 6-96.

The pole top structure asset group

We consider that the AER's rationale for arriving at its alternative forecast for the 'pole top structures' asset group is incorrect and does not adequately allow for its findings in other areas of our replacement forecast – most notably its repex model forecast.

Our Original Proposal included a replacement forecast for pole top structures that reflected our need for an increase over historical replacement levels for that asset group. The AER rejected our forecast and substituted a forecast that reflected historical levels, stating it:

> *'…did not consider SA Power Networks had justified the increase in expenditure from the last regulatory control period of the level it had proposed. In particular, it had not established a change in risk that would necessitate such a significant increase. Given this, we do not consider there is sufficient justification for a step increase in pole top structure repex in the 2015–20 regulatory control period…'*[49]

Pole top structures are high volume, low cost assets associated with our overhead network, similar to many of the assets the AER assessed through its repex model. Even though pole top structures were not assessed through the repex model, the model's broad findings are that we are in a significant upward phase of our replacement cycle for our overhead network assets, and therefore, this finding should have carried significant weight in the AER's considerations.

Further, the majority of pole top assets were installed at the same time as the poles and conductors – and are subject to the same service and environmental conditions such as corrosion, vibration, UV degradation.

The AER's repex model forecasts the need for a significant increase in the asset groups assessed through the model, an increase of 64% using the AER's preliminary decision and 82% allowing for our correction noted above. The pole top structure forecast in our Original Proposal reflected a far more modest increase of 36%.

For this reason, our Revised Proposal includes a pole top structure forecast that is in line with our Original Proposal of $71.6 (June 2015, $ million excluding overheads, including the balancing item adjustment), which represents a $20.1 (June 2015, $ million excluding overheads, including the balancing item adjustment) increase to the amount approved in the AER's Preliminary Determination.

Taking into account the two replacement expenditure adjustments noted above, our revised total expenditure forecast for replacement is $731.8 (June 2015, $ million – including overheads).

Compliance with our Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP)

As explained in our Original Proposal, SA Power Networks is required under the conditions of its Distribution Licence and section 25 of the *Electricity Act 1996* (SA) to comply with its ESCoSA approved SRMTMP.

SA Power Networks accepts the adjusted AER replacement forecast on the basis that we will have all of our assets fully inspected and within their current inspection cycle by December 2018. At that time, SA Power Networks will be in better a position to understand the actual defect find rate. This will enable us to develop forecasts for the 2020-25 RCP to undertake the necessary rectification work required to return the risk profile of our network to acceptable historic levels (consistent with our

[49] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 6-106.

SRMTMP) within the 10 year period as discussed with the OTR on 25 August 2014, and 22 June 2015. At a recent meeting the OTR accepted this approach on the basis that we adopt a risk based approach addressing the highest risk work first, that we review the situation in 2018 when all asset inspections are within current inspection cycles and that all necessary actions to achieve the 10 year program will be reviewed at the time.

SA Power Networks considers this approach:

- constitutes the 'reasonable steps' that must be taken by SA Power Networks to ensure that its distribution system is safe and safely operated (in accordance with section 60(1) of the *Electricity Act 1996* (SA)); and
- exhibits the degree of diligence, prudence and foresight that would reasonably be expected from a significant proportion of NSPs operating under comparable conditions in the NEM (as required by clause 5.2.1(a) of the NER and the definition of 'good electricity industry practice').

Furthermore, certain elements of the SRMTMP require quite specific compliances and, in accordance with the NER, SA Power Networks should be provided with a reasonable opportunity to recover at least the efficient costs of complying funding must be granted to comply with all regulatory obligations and requirements.[50]

7.4.5 Revised Proposal

SA Power Networks' revised forecast capital expenditure for asset replacement for the 2015-20 RCP is $731.8 (June 2015, $ million), as set out in Table 7.6.

Table 7.6: SA Power Networks' forecast replacement capital expenditure for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Replacement	128.3	145.8	152.0	154.4	151.4	731.8

[50] Section 7A(2)(b) of the NEL

7.5 Augmentation

In its Preliminary Determination the AER did not accept our forecast total augmentation capital expenditure of $884.0 (June 2015, $ million). Instead, the AER included its substitute estimate of $504.7 (June 2015, $ million, excluding escalations adjustment). SA Power Networks accepts some but not all of the AER's preliminary decisions on augmentation. Table 7.7 below summarises the augmentation expenditure by key driver, outlining the expenditure forecast in our Original Proposal, the expenditure approved in the AER's Preliminary Determination and our Revised Proposal expenditure.

Table 7.7: Augmentation capital expenditure forecast by key driver for the 2015-20 RCP (June 2015, $ million)

Augmentation	Original Proposal	Preliminary Determination	Revised Proposal	Comment
Augmentation	**884.0**	**504.7**[51]	**635.1**	
Demand driven	**345.4**	**324.9**	**325.7**	
Core program	*269.9*	*269.9*	*270.4*	*Accept, see below*
Quality of Supply	*55.0*	*55.0*	*55.3*	*Accept, see below*
Two-way *network*	*20.5*[52]	*0*	*0*	*Accept, see below and Section 7.11*
Safety	**321.1**	**21.9**	**107.9**	
Core program	*21.9*	*21.9*	*21.9*	*Accept, see below*
Bushfire mitigation program	*74.7*	*0*	*40.6*	*Do not accept, see below and Section 7.6*
Bushfire safer places	*128.6*[53]	*0*	*26.8*	*Do not accept, see below and Section 7.7*
Back-up protection	*18.4*[54]	*0*	*18.6*	*Do not accept, see*

[51] All analysis in this Revised Proposal has been undertaken at the category level to allow comparison with the AER's preliminary decisions at the same category level. We note an anomaly in the AER's preliminary decision summation at the Augmentation level, where we are unable to reconcile sub categories as per Table 7.7 to the total preliminary decision Augmentation expenditure in the AER's capital expenditure models. Note that overheads and the balancing item have been reallocated to our sub categories of expenditure for reporting on a like for like basis.

[52] Included $1.1 million for targeted monitoring of HV feeders in country substations. In the Revised Proposal this amount has been excluded from demand and included in strategic for RIN compliance.

[53] This forecast was previously included in the forecast capital expenditure associated with our bushfire mitigation program.

[54] This forecast was previously included in the forecast capital expenditure associated with our bushfire mitigation program.

Augmentation	Original Proposal	Preliminary Determination	Revised Proposal	Comment
				below and Section 7.8
Road safety program	*77.5*	*0*	*0*	*Accept, see below*
Reliability	**58.8**	**28.1**	**59.5**	
Maintaining reliability	*28.1*	28.1	*28.3*	*Accept, see below*
Hardening the network	*17.0*	*0*	*17.3*	*Do not accept, see below and Section 7.9*
Low reliability feeders	*8.5*	*0*	*8.6*	*Do not accept, see below and Section 7.9*
Remote communities (Hawker and Elliston)	*2.4*	*0*	*2.4*	*Do not accept, see below and Section 7.9*
Micro-grid trial	*2.8*	*0*	*2.9*	*Do not accept, see below and Section 7.9*
Strategic	**96.9**	**47.2**	**80.0**	
Kangaroo Island cable	*47.2*	*47.2*	*47.5*	*Accept, see below*
Network Control	*25.8*	*0*	*26.5*	*Do not accept, see below and Section 7.10*
RIN compliance (HV monitoring)	*0.0*	*0*	*2.6*[55]	*Do not accept, see below and Section 7.11*

[55] This expenditure was previously included in the forecast capital expenditure associated with Demand – Quality of Supply Two-way network.

Augmentation	Original Proposal	Preliminary Determination	Revised Proposal	Comment
LV network monitoring	*16.1*	*0*	*3.5*	*Do not accept, see below and Section 7.12*
Asset condition monitoring	*6.0*	*0*	*0*	*Accept, see below*
NER compliance	*1.8*	*0*	*0*	*Accept, see below*
Environmental	**15.5**	**15.5**	**15.6**	**Accept, see below**
Network other (PLEC)	**46.3**	**46.3**	**46.4**	**Accept, see below**

Note: Excludes the AER materials escalation adjustment.

Slight variations between the Original Proposal, Preliminary Determination and the Revised Proposal occur, even when we accept the AER's preliminary decision, due to materials and labour escalation adjustments, refer to Section 7.22 of this chapter.

We discuss the AER's Preliminary Determination and our detailed response in relation to augmentation expenditure by key driver below and in Sections 7.6 to 7.12 of this chapter. Below we briefly summarise our position on each key driver.

Demand driven augmentation

Core program

In its Preliminary Determination, the AER accepted our forecast demand driven augmentation (core program) capital expenditure. SA Power Networks accepts the AER's Preliminary Determination in relation to this program and has incorporated that decision into this Revised Proposal.

Quality of Supply

In its Preliminary Determination, the AER accepted our quality of supply capital expenditure.
SA Power Networks accepts the AER's Preliminary Determination in relation to this expenditure and has incorporated that decision into this Revised Proposal.

Two-way network

In its Preliminary Determination the AER did not accept our forecast two-way network monitoring capital expenditure. SA Power Networks partially accepts the AER's Preliminary Decision in relation to this expenditure as explained below.

SA Power Networks has an obligation[56] to maintain supply voltage at customer premises within the range specified in the Australian Standard, AS60038. In addition to our Quality of Supply (**QoS**)

[56] Electricity (General) Regulations 2012 (SA), reg 46 and EDC clause 1.1.5

program, in our Original Proposal we forecast capital expenditure of $20.5 (June 2015, $ million) to improve the monitoring of our network in rural areas by installing a monitoring system. Network monitoring is required to enable us to proactively manage the impact of photovoltaic (**PV**) solar connections on our network.

In its Preliminary Determination, the AER did not accept our capital expenditure forecast for demand driven two-way network monitoring. Its primary reasons were that our forecast PV connections for the 2015-20 RCP were overstated compared to AEMO's forecast, and our reactive QoS approach has been effective in managing a significant uptake of solar PV in the 2010-15 RCP.

SA Power Networks accepts the AER's Preliminary Determination in relation to two-way network monitoring and has incorporated that decision into this Revised Proposal. However, we have also included in this Revised Proposal a revised program of $2.6 (June 2015, $ million) to install high voltage (**HV**) monitoring in our country substations that do not have SCADA control during the 2015-20 RCP. This program is necessary for us to obtain and comply with RIN reporting requirements, refer to Section 7.15 of this chapter for more detail.

There is also a revised program for strategic LV network monitoring, refer to Section 7.12.

Safety

Core program

In its Preliminary Determination, the AER accepted our forecast safety (core program) capital expenditure of $21.9 (June 2015, $ million). SA Power Networks accepts the AER's preliminary decision and has incorporated that decision into this Revised Proposal.

Bushfire mitigation program

In its Preliminary Determination the AER did not accept our forecast bushfire mitigation capital expenditure. SA Power Networks disagrees with the AER's preliminary decision because we must, in accordance with our regulatory obligations and requirements, take reasonable steps to mitigate the risk of fires caused by our distribution system in South Australia. The reasons for our revised forecast capital expenditure are explained in further detail in Section 7.6 to 7.8.

Bushfire safer places

In its Preliminary Determination the AER did not accept our forecast undergrounding for bushfire safety capital expenditure. SA Power Networks disagrees with the AER's preliminary decision because it has had no regard to the extent to which our capital expenditure forecast included expenditure to address the concerns of our electricity consumers. The reasons for our revised forecast capital expenditure are explained in further detail in Section 7.7.

Back-up protection

In its Preliminary Determination the AER did not accept our forecast back-up protection capital expenditure. SA Power Networks disagrees with the AER's Preliminary Decision because the back-up protection program is required to satisfy our regulatory obligations under clauses S5.1.9(c) and (f) of the NER and SA Power Networks' Network Directive – Distribution Protection Philosophy (**ND J1**), and to maintain the safety of the distribution system. The reasons for our revised forecast capital expenditure are explained in further detail in Section 7.8.

Road safety program

In our Original Proposal, we included an amount of $77.5 (June 2015, $ million) to underground targeted sections of power lines that have been repeatedly impacted by vehicles. This program was in direct response to the concerns our customers raised throughout our CEP, our collaborative strategic workshops on undergrounding of power lines and our Willingness To Pay (**WTP**) research.

In its Preliminary Determination, the AER did not accept our road safety undergrounding program for the following reasons:

> *'We do not accept the $74.2 million [excluding overheads] forecast because we consider that the proposed program is not required to maintain the safety or reliability of SA Power Networks' distribution system, and does not reasonably reflect the costs that a prudent operator, acting efficiently, would require to achieve the capex objectives.'*[57]

The AER was of the view that the capital expenditure objectives provide that SA Power Networks' forecast capital expenditure should only include expenditure to maintain the safety of the distribution system through the supply of SCS, and to comply with regulatory obligations or requirements, including in relation to reliability.[58] The AER considered the driver behind the road safety undergrounding program is to improve road safety rather than maintaining network safety or reliability, therefore the proposed expenditure was not justified.

In addition, the South Australian Minister for Mineral Resources and Energy submitted that road safety initiatives should be the responsibility of the relevant Government agencies, not the South Australian electricity customers and SA Power Networks.

SA Power Networks accepts the AER's Preliminary Determination in relation to this program and has not incorporated the road safety program into this Revised Proposal.

Reliability

Core program (maintaining reliability)

In its Preliminary Determination, the AER accepted our forecast reliability (core program) capital expenditure. SA Power Networks accepts the AER's preliminary decision and has incorporated that decision into this Revised Proposal.

Hardening the network

In its Preliminary Determination the AER did not accept our forecast hardening the network capital expenditure. SA Power Networks disagrees with the AER's preliminary decision because it has had no regard to the extent to which our capital expenditure forecast included expenditure to address the concerns of our electricity customers. The reasons for our revised forecast capital expenditure are explained in further detail in Section 7.9.

---

[57] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-60.
[58] Clause 6.5.7(a) of the NER provides that to the extent that there is no applicable regulatory obligation or requirement in relation to reliability, SA Power Networks is required to maintain the reliability of the supply of standard control services, and of the distribution system through the supply of SCS.

Low reliability feeders

In its Preliminary Determination the AER did not accept our forecast low reliability feeders capital expenditure. SA Power Networks disagrees with the AER's preliminary decision because it has had no regard to the extent to which our capital expenditure forecast included expenditure to address the concerns of our electricity customers. The reasons for our revised forecast capital expenditure are explained in further detail in Section 7.9.

Remote communities (Hawker and Elliston)

In its Preliminary Determination the AER did not accept our forecast remote communities (Hawker and Elliston) capital expenditure. SA Power Networks disagrees with the AER's preliminary decision because it has had no regard to the extent to which our capital expenditure forecast included expenditure to address the concerns of our electricity customers. The reasons for our revised forecast capital expenditure are explained in further detail in Section 7.9.

Micro-grid trial

In its Preliminary Determination the AER did not accept our forecast micro-grid trial capital expenditure. SA Power Networks disagrees with the AER's preliminary decision because it has had no regard to the extent to which our capital expenditure forecast included expenditure to address the concerns of our electricity customers. The reasons for our revised forecast capital expenditure are explained in further detail in Section 7.9.

Strategic

Kangaroo Island cable

In its Preliminary Determination, the AER accepted our Kangaroo Island (**KI**) cable forecast capital expenditure. SA Power Networks accepts the AER's preliminary decision and has incorporated that decision into this Revised Proposal. However, in its Preliminary Determination the AER requested that SA Power Networks address a number of matters in its Revised Proposal.

SA Power Networks accepts the final assessment of the AER's consultant, Energy Market Consultants Associates (**EMCa**) in supporting the replacement of the KI cable prior to the end of its economic life. However, SA Power Networks would like to clarify an incorrect assumption concerning voltage support made by EMCa, which further supports the KI cable replacement assessment.

EMCa has incorrectly assumed that voltage support on the 33kV sub-transmission line between Penneshaw and American River is required under all scenarios and therefore excluded this expenditure from its analysis. The proposed cable will have larger copper conductor (> 150mm^2 diameter) than the existing cable to accommodate the forecast cable rating over its asset life. A conductor with a greater cross sectional area incurs less voltage drop than a conductor with smaller cross sectional of the same length. Therefore the voltage drop through the new KI cable will be reduced, deferring the need to provide additional voltage support via a new 33kV voltage regulator station until 2045. When using the Regulatory Investment Test – Distribution (**RIT-D**) model, voltage support expenditure is included in the analysis, however EMCa's model only examines deferral scenarios until 2028/29. Option 1, 'run the cable to failure', requires voltage support in 2030 based on the existing growth rate. EMCa's net present value (**NPV**) results do not take this into consideration.

In its Preliminary Determination, the AER requested that SA Power Networks consider a further option to pay a deposit with a cable supplier to shorten the production lead time. SA Power Networks has contacted six cable suppliers in relation to this option and five of those six cable suppliers have advised us that a 'jump the production queue' option is not available. The reason for this is that this may ultimately cause delays to suppliers in producing other customer orders. Further, an option to prepay only applies if the cable date production window can be confirmed or fixed.

For the single cable supplier that advised it may be possible to accept this option, that supplier has not yet actually made any commitment to being able to do so. In order to make such a commitment, that supplier still has to consider the opportunity cost related to other projects, the size of the order and the strategic importance of the project.

The AER also queried the feasibility of pre-purchasing and storing the cable:

> *'We understand that technology has been developed that would enable a storage solution. However, it is likely that the costs involved in the transport, storage and retrieval as set out by SA Power Networks would exceed the benefits of deferring installation until the existing cable fails.*[59]

Most of the cable suppliers we have consulted have confirmed the full length of the cable can be coiled. However, they have advised that it is costly and inefficient to load the cable onto a ship, unload the cable off that ship for storage and then load the cable back onto a cable laying ship. Instead, those cable suppliers have recommended that manufactured submarine cables be loaded directly onto a cable laying ship. This will avoid the risk of damaging the cable during extra handling operations which require the utmost care and expertise.

One cable supplier has also confirmed that it would be a very costly exercise to transport the cable and store a single long length of submarine cable. A more feasible option would be to transport the cable in 500 metre lengths on 32 drums. This would require many straight joints during the actual installation. However, that method is not recommended by that supplier or by SA Power Networks, as cable joints are a common mode of failure.

In submissions to our Original Proposal, some stakeholders were concerned that we may not have not adequately considered alternative renewable generation options. Business SA and Total Environment Centre (**TEC**), in particular, were critical of the fact that King Island was used as a basis for costing a renewable generation option, citing King Island as not representing best practice.

Since the successful application of hybrid renewable generation on King Island, Flinders Island and Coober Pedy have been adopting renewable energy enabling technologies developed by Hydro Tasmania. However, even if we were to assume that King Island is unsuitable for benchmarking purposes, the Flinders Island and Coober Pedy Renewable Hybrid Projects still support the fact that a renewable generation solution on KI as an alternative to the submarine cable is not economically viable.

Flinders Island has an installed generation capacity of 2.8MW with a peak load demand of approximately 1.2MW (being 15% of KI's current peak load). The Flinders Island Renewable Energy Integration Project, which is due to be completed in November 2016, will see an investment of $12 (June 201$, $ million) of which $5.5 million (or 43% of the total project cost) is funded by the Australian Renewable Energy Agency (**ARENA**).

Similarly, the Coober Pedy power station, operated by Energy Developments Limited (**EDL**), has an installed generation capacity of 3.9MW with a peak load of approximately 3MW (being 50% of KI's current peak load). SA Power Networks understands that the Coober Pedy Renewable Hybrid Project will receive $18.5 million from ARENA for its 2015 project to install up to 2MW of solar PV and 3MW of combined wind generation and battery storage.

---

[59] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-67

ARENA has supported, on average, 40% of the total cost of hybrid enabling technology projects valued above $2 million. This is fairly consistent with the percentage of funds provided to the Flinders Island Project (which is 43% of the total cost). By applying a similar 40% - 43% of project funding, the Coober Pedy Project is estimated to cost approximately $43–$46 (June 2015, $ million) excluding operating expenditure and fuel costs. This means that a comparably scoped hypothetical KI project could conceivably cost $84–$92 (June 2015, $ million excluding annual operating expenditure) to implement a similar integrated renewable solution to the Flinders Island and Coober Pedy power stations.

In its submission on our Original Proposal, Business SA noted that while a detailed study would be needed to confirm the estimate, on the basis of alternative benchmarks a '*nominal 7MW wind farm on Kangaroo Island would therefore cost approximately $21 million ($2014–15) on that basis, including integration technology.*'[60] Based on our analysis, this Business SA estimate significantly underestimates the costs involved.

Using the cost analysis model created by EMCa and accepted by the AER, SA Power Networks has, in developing this Revised Proposal, developed a preliminary NPV analysis for a non-network hybrid power station on KI, to determine if a renewable option is more efficient than the installation of the second submarine cable. This NPV analysis has identified that by taking into account only 40-60% of the projected annual fuel cost, the net present cost of a 7MW wind farm (the non-network solution recommended by Business SA), is three times the cost of our proposed cable solution. This analysis excludes other significant costs associated with the 33kV network upgrade, the operating and maintenance of the wind farm and the integration of existing renewable and new smart grid systems. Adding these costs into the analysis, the net present cost is significantly greater than the cable replacement solution.

To be comparable with the cable replacement solution, a renewable wind farm solution must be capable of displacing more than 85% of the annual fuel usage of the hybrid power station. As far as SA Power Networks is aware, an 85% reduction of fuel usage is not feasible at this time because the capacity factor of wind turbines, which is the ratio between average power produced and full capacity, is only around 30 – 40%.

From the data available, it appears renewable generation sources are only economical in isolated locations with no access to an established distribution network, and where expensive diesel energy can be displaced. As KI has an existing network, renewable generation sources are unable to compete with a traditional grid solution, at this time.

Finally, SA Power Networks notes that a formal RIT-D process will be undertaken prior to committing to the installation of a second undersea cable. This process will allow third party proponents to submit non-network solutions for due consideration.

Further details on our proposed KI cable replacement, and the specific concerns raised by Business SA, the Energy Consumers Coalition of South Australia and the Total Environment Centre, can be found in Attachment G.1a and G.1b: *Kangaroo Island submarine cable – additional supporting information*.

Network control

In its Preliminary Determination the AER did not accept our forecast network control capital expenditure. SA Power Networks disagrees with the AER's preliminary decision because the network control expenditure is required to maintain the quality, reliability and security of SA Power Networks

[60] Business SA, *Submission to the Regulatory Proposal 2015-20*, page 24.

SCS (refer clauses 6.5.7(a)(3) and 6.5.6(a)(3) of the NER).The reasons for our revised forecast capital expenditure are explained in further detail in Section 7.10.

RIN compliance (HV monitoring)

In its Preliminary Determination the AER did not accept our forecast QoS two-way network capital expenditure. SA Power Networks disagrees with the AER's preliminary decision because HV monitoring is necessary to achieve the capital expenditure objective to 'comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.' The reasons for our revised forecast capital expenditure are explained in further detail in Section 7.11.

LV network monitoring (Two-way network)

In its Preliminary Determination the AER did not accept our forecast LV network monitoring (two-way network) capital expenditure. SA Power Networks disagrees with the AER's preliminary decision because we do not agree with the AER's assessment that we will be able to meet our regulated obligation to maintain the supply voltage to the Australian Standards in areas of high solar PV penetration in the 2015-20 RCP using existing approaches. The reasons for our revised forecast capital expenditure are explained in further detail in Section 7.12.

Asset condition monitoring

The strategic asset condition monitoring program is discussed in the replacement expenditure section of the AER's Preliminary Determination and was assessed accordingly. SA Power Networks accepts the AER's preliminary decision and has incorporated that decision into this Revised Proposal.

NER compliance

The strategic NER compliance program is discussed in the replacement expenditure section of the AER's Preliminary Determination and was assessed accordingly. SA Power Networks accepts the AER's preliminary decision and has incorporated that decision into this Revised Proposal.

Environmental

In its Preliminary Determination, the AER accepted our forecast environmental capital expenditure. SA Power Networks accepts the AER's preliminary decision and has incorporated that decision into this Revised Proposal.

Other - PLEC

In its Preliminary Determination, the AER accepted our forecast Power Line Environmental Committee (**PLEC**) capital expenditure. SA Power Networks accepts the AER's preliminary decision and has incorporated that decision into this Revised Proposal.

7.6 Augmentation - Safety – Bushfire mitigation program

SA Power Networks has revised its bushfire mitigation program for the 2015-20 RCP. The forecast capital expenditure for the revised bushfire mitigation program is $40.6 (June 2015, $million).

The revised bushfire mitigation program focuses on the following three key strategies:

- Replacement of manual 33kV, 19kV and 11kV reclosers with fast operating SCADA controlled units – proposed capital expenditure $18.1 (June 2015, $ million);
- Replacement of rod air gaps and current limiting arc horns with modern surge arresters – proposed capital expenditure $12.4 (June 2015, $ million); and
- Reconstructing metered mains – proposed capital expenditure $10.1 (June 2015, $ million).

The remaining bushfire mitigation strategies which formed part of SA Power Networks' original bushfire mitigation program are now addressed in other sections of this Revised Proposal. In particular:

- The proposed program for the replacement of high-risk power lines with modern construction (bushfire safer places and targeted undergrounding supported by willingness to pay findings) has been modified and addressed as a separate program in Section 7.7 of this chapter;
- The back-up protection project is now being addressed as a separate program in Section 7.8 of this chapter; and
- The proposal to undertake field simulation testing and trial installation of Ground Fault Neutralisation Technology has been deferred until more evidence is available concerning the effectiveness of this technology (eg the Victorian DNSP's are currently installing this technology and this will in time provide detailed evidence concerning the effectiveness of this technology under Australian conditions).

It follows that this section of our Revised Proposal focuses on the evidence that has been previously provided by SA Power Networks in support of the strategies which make up the revised bushfire mitigation program and other information which supports the finding that this capital expenditure is required in order to achieve the capital expenditure objectives of complying with all applicable regulatory obligations and requirements and maintaining the safety of the distribution system.

This section of the Revised Proposal also addresses various issues raised by the AER in its Preliminary Determination concerning our original bushfire risk mitigation program and provides additional supporting evidence and information where that is required in order to demonstrate that the forecast capital expenditure associated with the revised bushfire risk mitigation program reflects what a prudent and efficient DNSP would require to achieve the capital expenditure objectives.

7.6.1 SA Power Networks’ Original Proposal

SA Power Networks proposed a forecast capital expenditure of $221.7 (June 2015, $ million) for bushfire mitigation in its Original Proposal.

7.6.2 AER’s Preliminary Determination

In its Preliminary Determination, the AER formed the view that SA Power Networks' proposed bushfire mitigation program was not required to maintain the reliability and safety of the network and would therefore not constitute a prudent and efficient investment in the network. In particular, the AER stated that its alternate total forecast capital expenditure estimate already factored in expenditure related to SA Power Networks 'business as usual' bushfire risk management.

In forming this view, the AER appears to have given little weight to the fact that the bushfire mitigation program was specifically designed to:

- achieve the combined capital expenditure objectives of complying with SA Power Networks' applicable regulatory obligations and requirements associated with the provision of SCS and maintaining the safety of the distribution system through the supply of SCS; and
- address the bushfire safety concerns of consumers and the broader community identified by SA Power Networks during the course of its CEP.

The AER lists various reasons for rejecting the forecast capital expenditure for the proposed bushfire mitigation program. In particular, the AER considered that:[61]

- SA Power Networks' proposed capital expenditure is not required to maintain the reliability and safety of its network;
- SA Power Networks has not provided sufficient evidence of increased bushfire risk from ignition by power lines in South Australia;
- there has been no change to regulations and/or safety standards related to bushfire risk that would justify additional expenditure;
- SA Power Networks' proposed capital expenditure is not a prudent and efficient investment; and
- SA Power Networks has not undertaken a cost benefit analysis of the program and therefore its analysis has not properly evaluated the costs versus the benefits of the proposed bushfire risk mitigation program.

The AER's commentary in relation to each of these reasons primarily focuses on the undergrounding aspects of SA Power Networks' original bushfire mitigation program. As noted above, the undergrounding aspects of our original bushfire mitigation program have been removed from the scope of our revised bushfire risk mitigation program and the associated forecast capital expenditure. This section of our Revised Proposal focuses on the application of the above reasons to the core bushfire risk mitigation strategies listed above and explains why the AER's reasons do not justify the rejection of the forecast capital expenditure associated with those core bushfire risk mitigation strategies.

7.6.3 SA Power Networks’ response to AER Preliminary Determination

The forecast capital expenditure is required to achieve the capital expenditure objectives

The AER asserts that SA Power Networks' proposed capital expenditure for its bushfire mitigation program is not required to maintain the reliability and safety of its network. SA Power Networks rejects this finding.

SA Power Networks submits that the forecast capital expenditure for its revised bushfire mitigation program is required in order to achieve the capital expenditure objectives of:

- compliance with all applicable regulatory obligations and requirements associated with the provision of SCS; and
- the maintenance of the safety of the distribution system through the supply of SCS.

[61] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 6-50.

SA Power Networks also submits that a total forecast capital expenditure that does not include forecast capital expenditure on account of the revised bushfire mitigation program:

- will not achieve the capital expenditure objectives[62] (because this capital expenditure is required to comply with SA Power Networks applicable regulatory obligations);
- will not provide SA Power Networks with a reasonable opportunity to recover at least the efficient costs SA Power Network will incur in complying with its applicable regulatory obligations and requirements;[63]
- cannot reasonably reflect the capital expenditure criteria[64] (because each of the criteria are linked to the achievement of the capital expenditure objectives); and
- will not promote efficient investment in and efficient operation and use of electricity services for the long term interests of consumers of electricity with respect (in particular) to safety of the supply of electricity.[65]

Central to these considerations is the meaning of complying '*… with all applicable regulatory obligations or requirements associated with the provision of standard control services'* and maintaining '*… the safety of the distribution system through the supply of standard control services.*'

Duty to take reasonable steps to ensure network is safe and safely operated

Section 60(1) of the *Electricity Act 1996* (SA) (**Electricity Act**) requires SA Power Networks to take reasonable steps to ensure that its distribution system is safe and safely operated.

There is no doubt that this is an applicable regulatory obligation or requirement associated with the provision of SCS. There is also no doubt that this regulatory obligation requires SA Power Networks to take 'reasonable steps' to ensure that its distribution system does not cause bushfires.

It follows that the scope and extent of SA Power Networks' obligation under section 60(1) will depend upon what amounts to 'reasonable steps' to ensure that this outcome is achieved.

We have obtained legal advice which considers:

- the proper interpretation of this obligation;
- the parallels between a duty to take reasonable steps to ensure the network is safe and safely operated and the duty of care that applies to a DNSP under the common law of negligence;
- the factors which will inform the current meaning of the obligation to take reasonable steps to ensure the network is safe and safely operated; and
- the manner in which the findings from the Victorian Bushfire Royal Commission (**VBRC**) and the Victorian Powerline Bushfire Safety Taskforce (**PBST**) have informed the current meaning of the obligation to take reasonable steps to ensure the distribution system is safe and safely operated.

That legal advice confirms that the obligation to take reasonable steps to ensure that the distribution system is safe and safely operated imposes an obligation on SA Power Networks which essentially reflects SA Power Networks' duty of care under the common law of negligence. It follows that the assessment of what amounts to 'reasonable steps' to ensure that the distribution system is safe and safely operated requires SA Power Networks to have regard to objectively determined standards of safety.

---

[62] Clause 5.6.7(a) of the NER.
[63] Section 7A(2)(b) of the NEL.
[64] Clause 6.5.7(c) of the NER
[65] Section 7 of the NEL.

In other words, SA Power Networks needs to ask what would a reasonable and prudent electricity distribution system operator faced with the same conditions and circumstances as apply to SA Power Networks do to ensure that the distribution system is safe and safely operated. This would clearly require SA Power Networks to have regard to (amongst other things):

- the findings of the VBRC and the PBST concerning the ignition risks associated with the operation of certain types of distribution network assets in bushfire risk areas and the steps which can and should be taken to minimise those ignition risks;
- 'good electricity industry practice' (as defined in Chapter 10 of the NER); and
- improvements in knowledge and technology and authoritative expert opinion.

In our view, it is clear that the findings of the VBRC and the PBST in relation to the ignition risks associated with manual reclosers and aged and poorly maintained low voltage power lines and other assets,[66] would (to the extent that those findings are relevant to the SA Power Networks distribution system and circumstances) inform the meaning of *'reasonable steps*' and *'good electricity industry practice*' under the South Australian regulatory obligations and requirements.

The VBRC was a broad ranging enquiry which sought and critically evaluated a significant body of expert evidence concerning the ignition risk associated with the operation of distribution system assets in bushfire risk areas. Its recommendations reflect the outcomes from this detailed evaluation process and have been widely accepted by the Australian electricity industry and Governments.

These recommendations were further evaluated by the PBST utilising a precautionary based approach to risk assessment to determine the best way to address and minimise the risks identified by the VBRC. In both forums expert evidence was obtained which conclusively demonstrated the areas of critical risk and the manner in which those risks should be addressed.

SA Power Networks clearly must have regard to these findings and recommendations when determining what it needs to do to discharge its obligation to take reasonable steps to ensure the distribution system is safe and safely operated. In our view, the AER must also have regard to these findings and recommendations when determining whether our forecast capital expenditure for the revised bushfire mitigation programs is required to achieve the capital expenditure objectives related to compliance with regulatory obligations and requirements and maintaining the safety of the distribution system. SA Power Networks' obligation under section 60(1) of the *Electricity Act* is supplemented by its regulatory obligation under clause 5.2.1(a) of the NER to maintain and operate all equipment that forms part of its facilities in accordance with relevant laws, the requirements of the NER and good electricity industry practice and relevant Australian Standards.

Once again, what constitutes 'good electricity industry practice' will by definition be informed by the degree of skill, diligence, prudence and foresight that reasonably would be expected from a significant proportion of operators of facilities forming part of the Australian electricity system under conditions comparable to those applicable to SA Power Networks.

In other words, in determining what SA Power Networks is required to do to discharge this obligation, SA Power Networks must take into account the practices of other Australian electricity network operators. These practices have also been informed by the evidence submitted to the VBRC and the PBST, and the comments and resulting recommendations of the VBRC and PBST concerning the steps

---

[66] Victorian Bushfires Royal Commission, *'The 2009 Victorian Bushfires Royal Commission Final Report'*, 31 July 2010, Vol II, Ch 4 (Electricity-Caused Fire); Powerline Bushfire Safety Taskforce, *'Final Report'*, 30 September 2011.

which should be taken in order to minimise the risk of a fire being caused by the operation of an electricity distribution system in a bushfire risk area.

The fact that the some of the recommendations of the VBRC were then considered and implemented by the PBST via the introduction of specific and mandated regulatory obligations does not prevent those comments and recommendations also informing what amounts to good electricity industry practice and 'reasonable steps' for the purposes of ensuring that a distribution system is safe and safely operated (ie the fact that the South Australian government did not amend the *Electricity Act* or regulations to expressly mandate (for example) the replacement of manual 33kV, 19kV and 11kV reclosers with fast operating SCADA controlled units does not prevent a finding that 'reasonable steps' to ensure that the distribution system is safe and safely operated now includes replacing manual 33kV, 19kV and 11kV reclosers in bushfire risk areas with fast operating SCADA controlled units).

As SA Power Networks noted in its Original Proposal, the nature of the general duty imposed upon SA Power Networks under section 60(1) requires SA Power Networks to continually have regard to the latest and most authoritative evidence concerning the risks associated with operating a distribution system in a bushfire risk area and the reasonable steps that can be taken in order to minimise those risks.

We provided evidence in our Original Proposal that demonstrated our revised bushfire mitigation represents:

- a 'reasonable step' to ensure that the distribution system is safe and safely operated; and
- good electricity industry practice.

Further evidence in support of this conclusion is set out in Attachment G.2: *Bushfire mitigation – additional supporting information*.

Applicability of the Work, Health and Safety Act

SA Power Networks' activities are governed by the *Work Health and Safety Act 2012* (SA) (**WHS Act**).

SA Power Networks is a person conducting a business or undertaking within the meaning of section 5 of the WHS Act. It follows that SA Power Networks owes a non-delegable duty (in respect of health and safety to both its workers and all other persons who may be affected by assets within its management) to, <u>so far as is reasonably practicable</u>, ensure that its workplace is without risk to the health and safety of any person. In the context of dangers caused by its distribution system, SA Power Networks has a duty under the WHS Act towards all 'other persons' in the vicinity of its distribution system.

What is required of SA Power Networks in order to satisfy these duties depends on what actions are 'reasonably practicable'.

Section 18 of the WHS Act provides that what is 'reasonably practicable' in ensuring health and safety is that which is, or was at a particular time, reasonably able to be done in relation to ensuring health and safety, taking into account and weighing up all relevant matters including:

- the likelihood of the hazard or risk occurring;
- the degree of harm that might result from the hazard or the risk;
- what the relevant person knows, or ought reasonably to know, about the hazard or the risk;
- ways of eliminating or minimising the risk;
- the availability and suitability of ways to eliminate or minimise the risk; and

- after assessing the extent of the risk and the available ways of eliminating or minimising the risk, the cost associated with available ways of eliminating or minimising the risk, including whether the cost is grossly disproportionate to the risk.

It follows that SA Power Networks must first consider what can be done to remedy any risk to health and safety, and then consider (by reference to the above matters) whether it is reasonably practicable to take the identified action.

There is a clear presumption in favour of safety ahead of cost under the WHS Act. This is consistent with the rationale behind the notion of 'reasonably practicable'. In the context of the law of negligence, courts very rarely find that a reasonable person would not take safety measures solely because of their cost.

It is for this reason that the definition of 'reasonably practicable' in section 18 of the WHS Act introduces the requirement that the cost of taking a control measure must be 'grossly disproportionate' to the risk it seeks to address before it will not be reasonably practicable to take that measure. The use of this phrase is important as it (in part) addresses the complexities of weighing up cost and risk by promoting a transparent bias in favour of safety. Unless the cost of a control measure is grossly disproportionate to the risk, the control measure will be reasonably practicable.

Therefore, in order to discharge its statutory health and safety duties SA Power Networks is required to implement any control measures of which it is aware, provided that the cost of doing so is not grossly disproportionate to the risk it seeks to address. It follows that a typical (or standard) cost/benefit analysis is inappropriate when determining whether SA Power Networks is required to implement a particular control measure. The balancing exercise between safety and cost is weighted far more in favour of safety.

Maintaining '…the safety of the distribution system through the supply of standard control services.'

The Australian Energy Market Commission (**AEMC**) considered the meaning of these words in it 2013 Rule Determination concerning the Network Service Provider Expenditure Objectives.

The AEMC commented that current levels of safety may be appropriately influenced by safety standards in voluntary industry codes or Australia Standards in addition to regulated standards.[67] The AEMC concluded that it would not be appropriate to limit expenditure allowances to the regulated standards for safety.[68] In SA Power Networks' case, safety standards in voluntary industry codes or Australia Standards can and do inform what amounts to 'reasonable steps' to ensure that the distribution system is safe and safely operated.

The AEMC also noted that there is a risk of inefficiency if the decision of the standard setter is not given effect to in the regulatory process and one standard is used to assess compliance with regulatory obligations but a different standard is used to assess regulatory proposals. In SA Power Networks' case the standard setter is the South Australian Government who has elected to impose a 'reasonable steps' obligation on SA Power Networks understanding that this type of standard clearly requires SA Power Networks to objectively assess what steps are required from time to time to discharge this obligation (ie the steps required to discharge this obligation will change over time to reflect what a reasonable and prudent electricity distribution system operator faced with the same conditions and circumstances as apply to SA Power Networks would do to ensure that the distribution system is safe

---

[67] AEMC, *Network Service Provider Expenditure Objectives*, Final Rule Determination, 19 September 2013, page 10.
[68] AEMC, *Network Service Provider Expenditure Objectives*, Final Rule Determination, 19 September 2013, page 11

and safely operated). This is the standard that must be used by the AER to assess SA Power Networks' regulatory proposal.

Evidence of increased fire risk from ignition by power lines in South Australia

The AER asserts that SA Power Networks has not provided sufficient evidence of increased bushfire risk from ignition by power lines in South Australia. The AER states on page 6-52 of the Preliminary Determination that:

- Jacobs has not demonstrated that similar expectations in relation to the need for reduced bushfire starts are reasonably likely to exist in South Australia; and
- Jacobs provides no information to demonstrate that the South Australia a community's expectations in relation to bushfire starts have altered.

SA Power Networks disputes the first finding and notes that the level of fire risk is only one factor which will influence what amounts to reasonable steps in the context of ensuring that the distribution system is safe and safely operated.

The VBRC notes in its Final Report that:[69]

> *'The distribution businesses have long accepted that their assets have the capacity to start fires and that it is important to take steps to mitigate the risk of such fire starts.'*

The VBRC accepted that on days of extreme fire danger the percentage of fires caused by electrical distribution assets rises dramatically above the long-term average. In its Final Report, the VBRC quotes the director of Energy Safe Victoria, as saying that it was 'probably self-evident' that on days of extreme fire danger the percentage of fires caused by electrical distribution assets rises dramatically above the long-term average.[70]

This is also the case in South Australia.

SA Power Networks provided evidence in its Original Proposal confirming that the number of days of extreme fire danger per year was increasing and this trend was set to continue over the 2015-20 RCP. It appears that the AER accepted this evidence.

Therefore in simple terms if all other considerations remain the same, the increase in extreme fire danger days, coupled with the fact that the percentage of fires caused by electrical distribution assets rises dramatically above the long-term average on extreme fire days, means that the number of fires caused by electrical distribution assets will increase over the 2015-20 RCP. In other words if there is an overall increase in fire risk and the proportionate risk from electricity assets remains the same, there will be an increase in the number of fires caused by electricity assets on extreme fire danger days.

The VBRC and the PBST proceeded on the basis that the average number of fires started by electricity assets is relatively low and that between 1977 and 2009 various steps had been taken by Victorian DNSPs which substantially addressed some of the causes of fires. This resulted in a 'step' reduction in

---

[69] Victorian Bushfires Royal Commission, *'The 2009 Victorian Bushfires Royal Commission Final Report'*, 31 July 2010, Vol II, Ch 4 (Electricity-Caused Fire), page 150.
[70] Victorian Bushfires Royal Commission, *'The 2009 Victorian Bushfires Royal Commission Final Report'*, 31 July 2010, Vol II, Ch 4 (Electricity-Caused Fire), page 148.

the number of fires started by electricity assets. Against this background the VBRC still concluded that a lot more needed to be done.

In our view, the VBRC is far better placed than the AER to make an assessment concerning the correlation between the increase in extreme fire danger days and the increase in the risk of fires caused by electricity assets. In any event, the existence of even a relatively low level of risk:

- was seen to be unacceptable by the VBRC from a public policy perspective; and
- would be considered to be unacceptable in any event applying the precautionary-based approach to risk assessment and the reasonably practicable test prescribed by the WHS Act.

More importantly, the human and financial cost of a major bushfire mean that even a relatively low risk of fires caused by electricity assets in bushfire risk areas is unacceptable from a precautionary based risk assessment perspective. As was seen in Victoria in February 2009 the manifestation of this risk on an extreme fire danger day can lead to devastating consequences. In that case, five of the 15 fires which started on that day were caused by electrical assets. The same potential risk exists in South Australia and SA Power Networks must take reasonable steps to address this risk.

As noted above, the actual level of fire risk that is associated with the operation of distribution system assets in bushfire risk areas is only one factor which will inform what steps need to be taken by SA Power Networks in order to discharge its duty under section 60(1) of the *Electricity Act*. The fact remains that there is a risk and the VBRC formed the view after considering volumes of expert evidence that the risk was unacceptable and steps should be taken to address this risk. SA Power Networks has identified the steps that can and should be taken and the cost of taking those steps is not grossly disproportionate to the risk that is being addressed.

The AER states that Jacobs provides no information to demonstrate that the South Australian community's expectations in relation to bushfire starts have altered. SA Power Networks submits that the expectations of the South Australian community would be broadly similar to the expectations of the Victorian community as identified during the VBRC. This was confirmed through our CEP.

The AER appears to be suggesting that the number of bushfire starts need to increase above historical averages before SA Power Networks can take additional steps to address this risk. If this is a correct interpretation of the AER's position, then SA Power Networks would strongly dispute this assertion. Delaying the taking of reasonable steps pending actual evidence of increased fire starts would be unacceptable given the extreme consequences that could arise from a fire start. Faced with the consequences of a significant bushfire event, a Court would ask why the DNSP waited until a fire was caused by the type of asset that was identified by the VBRC as having an increased ignition potential before deciding to take reasonable steps to address that risk.

As noted above, these concerns have been vocalised by South Australian electricity customers through our CEP. As discussed at length in Chapter 3 of this Revised Proposal, our CEP has demonstrated that customers value safety very highly and want (and expect) SA Power Networks to undertake additional steps and programs of work to ensure ongoing community safety. This includes (without limitation) mitigating the risk of fire ignition in bushfire risk areas caused by electricity infrastructure and managing the associated risks from older deteriorating infrastructure in bushfire risk areas.

Further evidence concerning the level of fire risk associated with the operation of SA Power Networks' electrical assets in bushfire risk areas has been provided in Attachment G.2: *Bushfire mitigation – additional supporting information.*

Evidence of change to regulatory obligations and safety standards that justify additional expenditure

The AER states on page 6-52 of the Preliminary Determination that Jacobs offers no information to reasonably demonstrate that in SA Power Networks' circumstances it would be prudent to adopt the PBST initiatives reflected in the revised bushfire risk mitigation program. The AER then asserts that no information has been provided which demonstrates that these practices would be the most efficient option for addressing SA Power Networks' 'bushfire management' needs.

As discussed above, SA Power Networks is obliged to take reasonable steps to ensure that its distribution system is safe and safely operated and to, so far as is reasonably practicable, ensure that distribution system is without risk to the health and safety of any person. These standards of safety are objective and change over time. The legal interpretation of these obligations also supports the view that a precautionary-based approach to identifying steps to reduce bushfire risk should be taken. Under this approach, all reasonable practicable precautions are adopted based on a balance of:[71]

- the significance of the risk (eg – the magnitude, probability of occurrence, severity of harm); and
- the effort required to reduce it (eg – expense difficulty and utility of conduct).

This approach suggests that bushfire risk mitigation options should be implemented unless the cost of implementing those options is grossly disproportionate to the risk they are seeking to address. Expending the sum of $40 million over five years to address the potential risks identified by the VBRC that remain to be addressed in South Australia is clearly not grossly disproportionate to the risk that is being addressed. This bushfire risk mitigation program is the logical next step in the process of doing everything that is reasonably practicable to minimise the risk of fire starts caused by electricity assets in bushfire risk areas.

The SA Power Networks business cases, together with the Jacobs Report, demonstrate that the estimated costs of implementing the revised bushfire risk mitigation program are efficient and the timing for the revised program is clearly prudent taking into account the findings of the VBRC and the increased community focus on safety.

Further evidence in support of the efficiency and prudency of our revised bushfire mitigation program is set out in Attachment G.2: *Bushfire mitigation – additional supporting information*.

The AER notes on page 6-53 of the Preliminary Determination that the Office of the Technical Regulator (**OTR**) has also confirmed that SA Power Networks currently satisfies the existing regulations and standards relating to managing bushfires. SA Power Networks has also spoken to the OTR about the efficacy of its revised bushfire mitigation program. SA Power Networks recently advised the OTR of the necessary work to be undertaken under our revised bushfire mitigation program so that we meet our legal and regulatory requirements. The OTR acknowledged the nature and the basis for this work and accepted that SA Power Networks will keep the OTR informed of progress of implementation through our compliance reports.

Standards of safety change over time as industry knowledge, industry practices and community expectations change. Clearly the concept of maintaining the safety of the distribution system does not mean that safety standards will never change. The adoption of the concept of 'good electricity industry practice' in the NER is evidence of the changing nature of what amounts to maintaining the safety of the distribution system.

---

[71] Powerline Bushfire Safety Taskforce, *'Final Report'*, 30 September 2011, page 52.

This concept is also reflected in the wording used in section 60(1) of the *Electricity Act*. What amounts to 'reasonable steps' to ensure that the distribution system is safe and safely operated will change over time as safer methods of operation are developed and additional risk reduction methods are identified. The process of developing a forecast of the capital expenditure which will be required in order to achieve the capital expenditure objectives during a regulatory control period is an appropriate time to examine what constitute reasonable steps for the purpose of discharging this safety obligation.

The AER concludes that the capital expenditure for the bushfire risk reduction program is not justified in the absence of compelling evidence that SA Power Networks' current practices and procedures relating to managing bushfires are insufficient. SA Power Networks believes that the VBRC and the events which led to the establishment of the VBRC constitute compelling evidence that SA Power Networks should examine its current practices and procedures relating to the mitigation of fire risk in bushfire risk areas and adopt all reasonably practicable measures for mitigating that risk (consistent with good electricity industry practice at the time).

The VBRC noted in its Final Report that:[72]

> *'It is not satisfactory that the distribution businesses can decide that a specific level of bushfire risk is 'acceptable' and rely on the benefit of improved processes and technology to maintain that risk level (instead of reducing it) in order to decrease their operating costs or increase their profits. Distribution businesses should take all reasonable opportunities to reduce bushfire risk.'*

The AER also notes on page 6-53 of the Preliminary Determination that South Australia is the only State that has legislated the authority to the electricity entity to turn off the power in extreme bushfire weather, which further reduces the risk of fire starts from electricity assets in bushfire risk areas. Whilst SA Power Networks has this legislated power, SA Power Networks does not exercise its power under section 53 of the Electricity Act lightly. As noted by the PBST in its Final Report, this power has been used infrequently in South Australia and only in small areas where required due to the state of vegetation clearance or mechanical defect.[73] SA Power Networks has an agreed set of criteria and procedures for using this power which have been discussed with the Country Fire Service and the State Government.

The reason for limiting the use of this power was correctly enunciated by the PBST in its Final Report when it formed the view that: [74]

> *'under most circumstances, the potential impact on the community that may result from the deliberate turning off of powerlines on a temporary basis outweighs the risk of leaving them in service. There will only be limited circumstances where deliberate turning off of powerlines on a temporary basis is warranted on a lowest overall risk basis. However, this precaution may be reasonable and practicable in those limited circumstances.'*

When the power is deliberately turned off, communities will not have power for equipment such as computers, radio scanners or telephones that rely on power supply to monitor and communicate fire activities, for refrigeration of food supplies, or for pumps for fuel or water. The welfare of vulnerable members of the community, particularly, the very young, elderly and sick may also be threatened

[72] Victorian Bushfires Royal Commission, *'The 2009 Victorian Bushfires Royal Commission Final Report'*, 31 July 2010, Vol II, Ch 4 (Electricity-Caused Fire), page 161.
[73] Powerline Bushfire Safety Taskforce, *'Final Report'*, 30 September 2011, page 72.
[74] Powerline Bushfire Safety Taskforce, *'Final Report'*, 30 September 2011, page 74.

without power for medical equipment and air conditioning. This evidence supports the judicious use by SA Power Networks of this statutory power, due to the other risks to the community which arise when power is switched off. We would not be taking reasonable steps if we relied on this power to mitigate bushfire risk when the adoption of the other practices could reduce that risk.

The replacement of reclosers with fast operating SCADA controlled reclosers will enable us to better target and limit the use of our emergency power, thereby reducing the number of customers affected by turning off the power supply in accordance with this statutory right. One of the factors that inhibits the use of this statutory power is the fact that customers who are located immediately outside of BFRAs are often impacted by the cutting off of the power supply to the BFRA. If the number of customers who are affected by the use of this power can be reduced, the impact on customers related to the judicious use of this power can be reduced. Further information concerning the historical use of this power is set out in Attachment: G.2 *Bushfire mitigation* – additional supporting evidence.

SA Power Networks' Revised Proposal to replace reclosers with fast operating SCADA controlled reclosers is discussed in further detail later in this section.

SA Power Networks' proposed capital expenditure is a prudent and efficient investment

As noted above, the forecast capital expenditure for the revised bushfire mitigation program reflects the efficient and prudent costs of complying with SA Power Networks' applicable regulatory obligations related to bushfire mitigation.

Importantly, this program of work is not aimed at eliminating fire risk by the end of the next period. It is a targeted and prioritised program of work that is aimed at identifying and addressing the areas of our network that have the highest potential to cause a fire on high bushfire risk days in BFRAs and the reasonable steps that can and should be taken by SA Power Networks to mitigate that risk and bring SA Power Networks in line with good electricity industry practice.

The estimated costs of the revised program is prudent as that cost is not grossly disproportionate to the risk it is addressing and the program is required in order to discharge SA Power Networks' regulatory obligation to take reasonable steps to ensure that the distribution system is safe and safely operated.

Furthermore, the AER has not suggested that the estimated cost of the revised program is inefficient.

On page 6-53 of the Preliminary Determination the AER notes that the fact that the repex component for the 2015-20 RCP is higher than SA Power Networks' historical repex for the 2010-15 RCP should enable SA Power Networks to engage in additional safety-related work. The AER states that this further supports the AER's position that SA Power Networks' proposed incremental capital expenditure for a bushfire mitigation program has not been justified.

However, the forecast capital expenditure in relation to the revised bushfire mitigation program is not, and would not, be classified as 'replacement expenditure' under the AER's Expenditure Forecast Assessment Guideline. This expenditure is not being incurred to address deterioration of assets. This expenditure is being incurred to comply with our regulatory obligations. The fact that the assets in question would eventually be replaced does not mean that replacing them before the end of their economic life in order to comply with a regulatory obligation should be classified as replacement expenditure.

The AER has formed a view in relation to our allowance for replacement expenditure based on the application of the AER's repex model and the information we provided in our Original Proposal concerning our obligations under the ESCoSA approved SRMTMP. That allowance represents the

AER's views concerning the level of efficient and prudent replacement expenditure during the 2015-20 RCP. The fact that the efficient and prudent level of replacement expenditure during the 2015-20 RCP is higher than the efficient and prudent level of replacement expenditure during the 2010-15 RCP is an outcome from the proper application of the repex model and the revenue determination processes. It does not justify the rejection of a separate program of capital works which is required to comply with SA Power Networks' regulatory obligations.

SA Power Networks has properly evaluated the costs versus the benefits of the proposed bushfire risk mitigation program

On page 6-54 of the Preliminary Determination, the AER states that in terms of the SA Power Networks business case for the bushfire mitigation program (that excludes the expenditure undergrounding power lines in the BRFAs), SA Power Networks does not show that the proposed investment has an economic benefit. The AER states that the business case is qualitative and the other supporting material does not properly identify and measure the costs and benefits of the program as typically required in a cost/benefit analysis.

As noted above, a typical cost/benefit analysis is not appropriate in considering expenditure associated with preventative safety action.

As stated by the VBRC in its Final Report:[75]

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

The VBRC also highlights that this is not the first time that an economic regulator has taken an inappropriate approach to balancing the protection of human life against a cost/benefit analysis in assessing a bushfire mitigation revenue proposal.

In 2004 and 2005, well before the 2009 Victoria fires, Powercor, in similar manner to SA Power Networks, presented compelling submissions to the Essential Services Commission (**ESC**) (the economic regulator at that time), seeking revenue to place power lines in high risk bushfire areas underground. The ESC rejected Powercor's submission. The reasons put forward for rejecting that submission included that:

- The distribution businesses had failed to quantify the benefit or reveal the amount and network type to be undergrounded;
- The costs of undergrounding should be paid by the customer;
- The regulatory framework's incentive-based nature would ensure undergrounding where the benefits outweigh the costs; and
- The Victorian State Government Powerline Relocation Scheme funded up to half the undergrounding cost when a community benefit would result, and this was a more appropriate mechanism for obtaining revenue where there was community benefit.

The VBRC was scathing of these decisions. Without repeating the VBRC's findings in full, the VBRC was of the view that:[76]

---

[75] Victorian Bushfires Royal Commission, *'The 2009 Victorian Bushfires Royal Commission Final Report'*, 31 July 2010, Vol II, Ch 4 (Electricity-Caused Fire), page 158.

- The ESC's assertion that undergrounding costs should be paid by the customer ignores that fact that many of the benefits of undergrounding – in particular, the reduction in bushfire risk – accrue to the entire community;
- The ESC's approach ignored the fact that those benefits, including the saving of lives, are less amenable to measurement in financial terms;
- The ESC's argument that distributors would use underground cabling where the overall benefits outweighed the costs was incorrect; and
- The ESC's reliance on the Powerline Relocation Scheme was misplaced as the scheme concerned the undergrounding of power lines in areas where there was high pedestrian or vehicular activity or where environmental or cultural factors justify placement, and was not expressly concerned with reducing bushfire risk.

The parallels between the reasons given by the ESC in rejecting Powercor's bushfire mitigation submission and the reasons currently given by the AER in rejecting the forecast capital expenditure for SA Power Networks' original bushfire mitigation program are obvious.

Clearly in addressing risk to safety, consideration of the cost of preventative action, as well as the nature and magnitude of the risk, are relevant considerations. However, in complying with safety laws the role of cost/benefit analysis is not to determine whether the benefits of the proposed expenditure would outweigh the costs, but rather whether that cost is grossly disproportionate to the risk in question.

A finding by the AER which discounts forecast expenditure necessitated by safety considerations on the basis that the expenditure is unsupported by a cost/benefit analysis, would be a flawed finding based on an incorrect understanding of obligations created by the safety legislation.

Whilst compliance with health and safety obligations necessarily require the DNSPs to undertake risk assessments to identify and prioritise threats to health and safety, and to address such risks as efficiently as possible, works that are undertaken to address risks to health and safety are as a general rule not capable of being fully justified by reference to a cost/benefit analysis. This is because the chief benefits of such expenditure are typically the avoidance of death and serious injury.

Attempts to quantify such benefits and weigh them against the cost of the corrective action:

- are viewed as having questionable value in decision making; and
- expose a firm to extremely serious consequences under relevant laws if it decides against preventative action on the basis that the cost of addressing such a risk would exceed the benefit of avoiding death or serious injury.

For example, it is inconceivable that a prudent firm operating under workplace health and safety laws would decide against taking action to eliminate a safety risk on the basis that its cost would exceed the value placed by the firm on the life that would be saved by that action.

SA Power Networks' business case assesses the options for mitigating fire risk and adopts a program which achieves the greatest risk reduction for the lowest possible cost. SA Power Networks has expressed uncertainty regarding the financial benefits associated with a proposed program of work due to the difficulty in precisely quantifying the level of fire start reductions which would be achieved over the do nothing option. However, it is clear from the VBRC that the replacement of reclosers and

---

[76] Victorian Bushfires Royal Commission, *'The 2009 Victorian Bushfires Royal Commission Final Report'*, 31 July 2010, Vol II, Ch 4 (Electricity-Caused Fire), page 157.

other assets with modern equivalents will reduce the potential for electricity assets to start fires on extreme and catastrophic bushfire days in BFRAs.

It is only possible to quantify the level of fire start reduction in hindsight. However, if the implementation of these measures prevents one fire start on a catastrophic fire day, the benefits will significantly outweigh the costs of the relevant equipment.

The AER then criticises the Willis Report because it does not account for the probability of occurrence of a maximum probable loss event. The AER suggests that statistical models adjusted for various environmental factors demonstrate that the chance of a catastrophic bushfire caused by an electrical network is very remote and therefore the costs of these bushfire mitigation programs outweigh the benefits of further reducing the chance of this type of remote event occurring.

This reasoning denies the reality of the last 30 years of bushfires in South Australia and Victoria. The VBRC found that five of the 15 bushfires which were the subject of the VBRC were caused by a failure of electrical assets. A number of the 1983 Ash Wednesday bushfires were also caused by the failure of electrical assets.

There is a clear and recent history of major bushfires being caused by electrical assets and SA Power Networks would be remiss if it did not take this risk seriously and take all reasonable steps to reduce or remove this risk.

The extrapolations and conclusions drawn by the AER using models and data referred to in the Willis Report are not valid. To suggest a maximum probable loss bushfire event reoccurring period of 374 years is unreasonable. We engaged Risk Spatial to review the AER's comments and provide expert advice concerning the validity of those comments.

Based on the AER's logic the same comments would be equally applicable whenever those comments were made. For example, this type of statistical analysis if undertaken at the beginning of 2009 would suggest that the February 2009 Victorian bushfires were an extremely unlikely and remote occurrence. However, five of the 15 bushfires which started on 6 February 2009 were caused by electrical assets. A number of those fires caused massive human and economic loss. With the wrong combination of weather conditions, location of the point of ignition and vegetation load, any fire started by electrical assets could develop into a catastrophic bushfire.

For further information on the use of statistics to determine the probability of a bushfire event, refer to Attachment G.3 *Bushfire Risk Report*.

In developing its bushfire mitigation program, SA Power Networks cannot ignore this possibility even if simple statistical analysis (which SA Power Networks does not agree with) suggests that the likelihood of an occurrence is very low.

As noted above, the probability of occurrence of this type of catastrophic event is not a relevant consideration in assessing whether or not it is appropriate to undertake a bushfire risk mitigation program designed to significantly minimise the potential for spark generation by electricity assets located within bushfire risk areas. Adopting the reasonably practicable concept contained within the WHS Act, the cost of taking the mitigation actions would need to be grossly disproportionate to the risk it seeks to address before it would not be reasonably practicable to take those measures. SA Power Networks submits that this is clearly not the case with respect to it revised bushfire mitigation program.

AER analysis of costs and benefits of SA Power Networks' bushfire mitigation program

In its Preliminary Determination, the AER expressed a range of views concerning the likelihood of a major bushfire being caused by a fire ignited by SA Power Networks' electricity infrastructure and suggested that this likelihood coupled with the fact that the proposed bushfire mitigation program could not fully eliminate the risk, meant that the bushfire mitigation investment is very likely to have a benefit cost ratio approaching zero.

This approach to analysing the costs and benefits of any bushfire mitigation program is completely inappropriate.

To start with, it rests on an incorrect interpretation of the Willis analysis we provided to support our Original Proposal. It denies the reality of the last 30 years of bushfires in South Australia and Victoria. In Victoria, the VBRC found that five of the 15 bushfires that started on Black Saturday were caused by failures of electrical assets, while a number of the 1983 bushfires in South Australia were also caused by electrical assets. There is a clear and recent history of major bushfires being caused by electrical assets.

It also proceeds on the basis that a major bushfire is the only type of event that is relevant from a risk benefit analysis perspective. All bushfires have the potential to cause significant damage to people, property and livestock. Whether this potential loss is valued at $50 million, $100 million or $500 million is largely irrelevant to any risk benefit assessment. Any one of these 'lesser' bushfires could translate into a major bushfire given the right combination of conditions and even a so called 'lesser' bushfire can have a devastating effect upon individuals and the community.

SA Power Networks must in planning its bushfire mitigation program assume that the right combination of conditions could occur in the foreseeable future. It cannot rely on statistical probability analysis alone (particularly where that analysis is based on limited historical data that has been extrapolated forward using very broad based assumptions). Rather, SA Power Networks must take into account recent events and developments and the fact that significant bushfires have been caused by electrical assets in the recent past. See Attachment G.3 for a more detailed discussion concerning these issues.

Table 7.8 summarises the major fire events in South Australia over the past 30 years.[77]

[77] Victorian Bushfires Royal Commission, *'The 2009 Victorian Bushfires Royal Commission Final Report'*, 31 July 2010, Vol II, Appendix B (Fire in Southern Australia: A Summary, page 347.

Table 7.8: Major fire events in South Australia over the past 30 years

Date	Location	Impact
1974-1975	North-west of state	**Deaths:** Nil **Area burnt:** 16 million hectares
February 1983 (including Ash Wednesday)	Mt Osmond, Mt Gambier, South Barwon	**Deaths**: 28 **Buildings**: 333 Livestock: 250,000 Fencing: more than 10,000 kilometres **Area burnt**: more than 260,000 hectares
January 2005	Eyre Peninsula, Adelaide Hills	**Deaths**: 9 **Buildings**: 337 **Livestock**: 47,000 **Fencing**: 6,304 kilometres **Area burnt**: more than 145,000 hectares
December 2007	Kangaroo Island	**Deaths**: 1 **Area burnt**: 95,000 hectares

The AER's proposed approach suggests that no bushfire mitigation investment could ever be justified because no bushfire mitigation program could ever fully eliminate the risk.

We provided historical fire start data in relation to our distribution system in the Bushfire Mitigation Programs Business Case provided to the AER as Attachment 20.45 to the Original Proposal. To support this analysis we have also assessed a number of fire start and bushfire data in SA. This data demonstrates that we have, in the past, started a significant number of fires in BFRAs, and these fires are disproportionately high on extreme fire risk days. Any fire that starts on a high or extreme fire risk day could lead to a catastrophic bushfire event depending on weather conditions which are of course outside of SA Power Networks' control.

As discussed at length above, there is compelling evidence that our network causes fires. These fires could be very significant, and we cannot discount the possibility that under extreme circumstances one of these fires could contribute to a catastrophic bushfire as significant as Ash Wednesday or Black Saturday.

Having said that, the AER fails to recognise that catastrophic bushfire events are not the only events that have the potential to significantly and detrimentally impact South Australian communities. Setting aside the effects of climate change and the ongoing ageing of our network, continuing with current practices will mean we will continue to start fires over the next 30 years unless we take action to minimise this risk.

We do not believe it is reasonable to view this as an immaterial risk. Therefore we must, in accordance with our regulatory obligations and requirements, take reasonable steps to mitigate the risk of fires caused by our distribution system in bushfire risk areas. Our proposed bushfire mitigation program balances that risk against the costs of doing so and reflects a prudent and efficient program of works to be undertaken in the 2015-20 RCP.

Further information in relation to our current fire risk and bushfire mitigation program can be found in Attachment G.2: *Bushfire mitigation – additional supporting information*.

7.6.4 Revised Proposal

Reclosers

Reclosers are self-contained pole mounted circuit breakers with inbuilt fault detection mechanisms and control systems. For transient faults, reclosers interrupt supply allowing the fault to clear, and then automatically reclose to restore supply. For permanent faults, the recloser trips and remains open or 'locks out' until the line is patrolled and confirmed as safe to restore supply. These units are constructed to be pole mounted, either on overhead line pole structures or inside substations.

SA Power Networks has many manual 33kV, 19kV and 11kV reclosers in service which are part of its protection system to minimise the risk of injury and damage from an electrical fault and to limit the interruption of supply caused by a fault.

The majority of reclosers present on SA Power Networks' distribution system are around 40 to 50 years old. The operating system in these assets is predominately hydraulic for fault detection and operation. The limitations of these units, compared with modern units, includes slower fault clearing times, inflexible protection and control settings, and an inability to remotely monitor or control their operation. In addition, parts of our distribution system are only protected by HV fuses which do not operate fast enough to materially reduce the risk of fire ignition following the detection of a fault.

The VBRC in its Final Report found that:[78]

> *Further, and more importantly, in the case of permanent faults the [recloser's] operation can substantially increase the risk of fire. This is because when a permanent fault occurs – such as a tree falling on a conductor or a conductor breaking or otherwise falling to the ground – the [recloser] will repeatedly restore high-voltage electricity to the conductor. This multiplies the fault current escaping in circumstances where the conductor might be close to flammable material.*

Furthermore, evidence provided to the VBRC suggested that on high-risk bushfire days the proportion of permanent faults is much higher than the long-term average.[79] This means that on total fire ban days the reclosers provide fewer benefits in terms of ensuring reliability and are more likely to operate by restoring high-voltage electricity to a line that has experienced a permanent fault and when it does so, the conditions are more likely to result in a fault causing a fire to start, and if such a fire does start it might be impossible to control.[80]

Perhaps, most critically, the VBRC noted that the contribution of reclosers to bushfire risk should not be treated lightly and the Kilmore East fire (that resulted in the death of 119 people) probably would not have started had the reclose function on a particular recloser been suppressed on that day. [81]

This same risk exists in South Australia as well as Victoria given that SA Power Networks has many manual 33kV, 19kV and 11kV reclosers in service.

Further information concerning the risks associated with the use of manual reclosers in bushfire risk areas is set out in Attachment G.2: *Bushfire mitigation – additional supporting information*. We have

[78] Victorian Bushfires Royal Commission, *'The 2009 Victorian Bushfires Royal Commission Final Report'*, 31 July 2010, Vol II, Ch 4 (Electricity-Caused Fire), page 168.
[79] Ibid.
[80] Ibid.
[81] Victorian Bushfires Royal Commission, *'The 2009 Victorian Bushfires Royal Commission Final Report'*, 31 July 2010, Vol II, Ch 4 (Electricity-Caused Fire), page 169.

also included information in that Attachment concerning the benefits of installing and using modern high-speed reclosers in bushfire risk areas.

This risk can, however, be significantly reduced if reclosers that automatically turn off power lines when faults occur are operated with more sensitive settings and are operated more quickly.[82]

In order to mitigate this fire start risk and ensure the health and safety to both its workers and all other persons who may be affected by SA Power Networks' distribution system, SA Power Networks has historically disabled the reclose functions on its reclosers in BFRAs on high bushfire risk days. However, many of the reclosers can only be operated manually so crews are required to attend multiple sites in rural locations over a short time frame. This process is practically difficult (and in some instances impossible) to implement in the required time frame. In addition, SA Power Networks will not send its crews into dangerous situations on catastrophic bushfire days. This further limits the number of reclosers that can be manually operated on high bushfire risk days. This difficulty can be overcome through investment in remote controlled SCADA reclosers.

SA Power Networks is now proposing to target and replace specific manual reclosers in BFRAs with modern SCADA controlled units. This will bring SA Power Networks in line with current good electricity industry practice and significantly reduce the risk of fire starts when faults occur (which is more likely on high bushfire risk days). It will also avoid placing SA Power Networks' employees in high bushfire risk situations.

In addition, the replacement of reclosers with fast operating SCADA controlled reclosers will provide the incidental benefit of being better able to target and limit the use of SA Power Networks' emergency power as it will enable SA Power Networks to target specific feeders in turning off the power which will limit the number of customers affected on high bushfire risk days and avoid affecting customers immediately outside of BFRAs. As noted above, the impact on customers is one factor which limits the use of our statutory power to cut off supply on high bushfire risk days. If the number of customers affected can be reduced by using modern SCADA controlled reclosers, then this statutory power will be more effective and the resulting reduction in the level of ignition risk will be greater.

SA Power Networks prepared a business case for this bushfire mitigation strategy (Original Proposal – Attachment 20.45) and assessed the costs and benefits associated with it. However, as stated by the VBRC in its Final Report:

> *'Any assessment of the costs and benefits of suppressing the reclose function on ACRs must take account not only of the potential inconvenience resulting from a reduction in the reliability of supply but also the potentially catastrophic impact and cost of a bushfire if it starts on a high-risk day, when it might be difficult or impossible to control.'*

In light of its obligations under section 60(1) of the *Electricity Act*, clause 5.2.1(a) of the NER and the WHS Act, and the concerns of customers in relation to bushfire safety, SA Power Networks has formed the view that the potential for its reclosers to cause a fire on a high bushfire risk day is an identifiable risk that can be prevented by SA Power Networks, and would in fact provide other significant benefits to SA Power Networks (such as avoiding placing its employees in high bushfire risk situations and enabling it to better exercise its emergency power under the *Electricity Act*). The cost of the forecast capital expenditure associated with taking this preventative step is therefore not grossly disproportionate to that risk. Undertaking this strategy is a reasonable step that SA Power Networks is obliged under its regulatory obligations and requirements, and in accordance with good industry practice, to take at this point in time.

[82] Powerline Bushfire Safety Taskforce, '*Final Report*', 30 September 2011, page 9.

Additional information in support of this bushfire mitigation strategy can be found in Attachment G.2: *Bushfire mitigation* – Additional Supporting information. That Attachment also provides further detail in relation to the scope of this strategic program.

This strategy was also one of the bushfire mitigation strategies recommended by Jacobs as a practical, cost-effective strategy that would allow SA Power Networks to operate in a manner consistent with 'good industry practice'.[83] Jacobs' report can be found in Attachment 11.8 to our Original Proposal.

SA Power Networks' bushfire mitigation - recloser forecast expenditure for the 2015-20 RCP is summarised in Table 7.9.

Table 7.9: SA Power Networks' bushfire mitigation - reclosers capital expenditure (June 2015, $ million)

Safety – Bushfire mitigation	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Reclosers	3.5	3.6	3.6	3.7	3.7	18.1

Surge arrestors

Rod Air Gaps (**RAGs**) and Current Limiting Arcing Horns (**CLAHs**) are a legacy technology to protect equipment forming part of SA Power Networks electricity distribution system from the effects of overvoltages.

Like most Australian DNSPs, SA Power Networks' practice is now to use surge arrestors to protect its equipment, which are a more expensive but more reliable form of overvoltage protection.

There is evidence that failures have occurred to overhead line equipment forming part of SA Power Networks' distribution system because RAGs and CLAHs have failed when these devices are bridged by animals or birds and lightning strikes, and this has resulted the animals and birds falling to the ground and starting fires. For this reason, these older types of protection equipment have already been progressively phased out in other States in bushfire risk areas.[84]

In order to mitigate this risk, SA Power Networks is proposing to replace RAGs and CLAHs with modern surge arrestors. This would deliver clear reductions in the number of arcing events when these devices are bridged by animals or birds and lightning strikes. This would in turn reduce the likelihood of bushfires being started by hot metal particles falling onto dry ground and igniting local grasses and vegetation.

Given that RAGs are rarely used by other Australian DNSPs and most DNSPs have already phased out their use and now use surge arrestors for their power line overvoltage protection,[85] it is currently good electricity industry practice for a DNSP to use surge arrestors for their power line overvoltage protection. As noted above, this supports a finding that reasonable steps to ensure the safety of the distribution system would include the use of surge arrestors for power line overvoltage protection in BFRAs.

[83] Jacob, *Recommended Bushfire Risk Reduction Strategies for SA Power Networks: Final Report*, October 2014, p 11-14.
[84] This is discussed in Section 5.5 of the Jacobs report. The fire hazard is due to an open spark gap in older units, which can be breached, typically by birds, which can often results in a fire.
[85] Jacob, *Recommended Bushfire Risk Reduction Strategies for SA Power Networks: Final Report*, October 2014, p 23.

SA Power Networks has prepared a business case for this bushfire mitigation strategy and assessed the costs and benefits associated with it (Attachment G.2). In doing so, SA Power Networks has developed a targeted and phased program for the replacement of RAGs and CLAHs using a feeder (power line) prioritisation model to rank power lines for bushfire mitigation work.

In light of its obligations under section 60(1) of the *Electricity Act*, clause 5.2.1(a) of the NER and the WHS Act, and the concerns of customers in relation to bushfire safety, SA Power Networks has formed the view that the potential for its RAGs and CLAHs to cause a fire on a high bushfire risk day is an identifiable risk that can be prevented by SA Power Networks, and would bring SA Power Networks in line with good electricity industry practice. The cost of the forecast capital expenditure associated with taking this preventative step is therefore not grossly disproportionate to that risk. Undertaking this strategy is a reasonable step that SA Power Networks is obliged under its regulatory obligations and requirements, and in accordance with good industry practice, to take at this point in time.

Additional information in support of this bushfire mitigation strategy can be found in Attachment G.2: *Bushfire mitigation – additional supporting information*. That Attachment also provides further detail in relation to the scope of this strategic program.

This strategy was also one of the bushfire mitigation strategies recommended by Jacobs as a practical, cost-effective strategy that would allow SA Power Networks to operate in a manner consistent with 'good industry practice'.[86] Jacobs' report can be found in Attachment 11.8 to our Original Proposal.

SA Power Networks' bushfire mitigation – surge arrestor forecast expenditure for the 2015-20 RCP is summarised in Table 7.10.

Table 7.10: SA Power Networks' bushfire mitigation – surge arrestor capital expenditure (June 2015, $ million)

Safety – Bushfire mitigation	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Surge arrestors	2.4	2.4	2.5	2.5	2.5	12.4

Metered Mains

'Metered mains' refers to the electricity infrastructure between a revenue meter and a customer's switchboard, where the switchboard is remote from the meter.

There are approximately 4,840 metered mains installations in BFRAs in South Australia. They are typically found on SWER lines in rural areas, usually where multiple buildings or bore pumps owned by a single customer are supplied from a single meter, or multiple meters if there are multiple tariffs.

These metered mains were originally installed to aid the efficient reading of meters by co-locating all meters for properties in rural areas close or adjacent to a road. These metered mains, and the power lines that connect them to individual properties, were constructed in accordance with a range of standards including those specified by the responsible council and what the contractor deemed suitable at the time.

The current condition of metered mains, and the power lines connecting them to individual properties, ranges from those that met SA Power Networks' standards at the time of construction, those that did not meet those standards at the time of construction and those that met SA Power

[86] Jacob, *Recommended Bushfire Risk Reduction Strategies for SA Power Networks: Final Report*, October 2014, p 11 to 14.

Networks' standards at the time of construction but no longer meet SA Power Networks' current standards.

Uncertainty over the ownership of and responsibility for these assets has resulted in the lack of maintenance of assets and this has in turn resulted in potential health, safety and fire risks. The PBST has recognised that private overhead power lines have been implicated in many fires in the past.[87] This situation presents a current health and safety, and fire risks to SA Power Networks' distribution system as was demonstrated by the bushfire in the Parkerville region in Western Australia in 2014 that burnt approximately 392 hectares of bushland and destroyed 57 homes and seven outbuildings/sheds/carports and pergolas, and partially damaged a further six homes. That fire was caused by a private electricity pole falling that had not been properly maintained.[88]

In order to mitigate this risk, SA Power Networks is proposing to upgrade or replace these assets to ensure that they meet the required standards and clarify with individual property owners who will be responsible for the maintenance of the asset going forward. There are approximately 4,840 customers supplied by metered mains but we will only be undertaking work on metered mains with two or more spans. No work will be undertaken on metered mains that are underground or single span because they present minimal fire risk.

SA Power Networks has already started inspecting and recording the installation condition of these assets in preparation for the broader repair task. This has assisted SA Power Networks in preparing a business case for this bushfire mitigation strategy and assessing the costs and benefits associated with it.

Additional information in support of this bushfire mitigation strategy can be found in Attachment G.4: *Metered mains – additional supporting information*. That Attachment also provides further detail in relation to the scope of this strategic program. The history to this program is complicated and better addressed in the Attachment.

In addition, our business case on metered mains has been updated since our Original Proposal and can be found in an attachment to the *Bushfire mitigation – additional supporting information* document.

In light of its obligations under section 60(1) of the Electricity Act, clause 5.2.1(a) of the NER and the WHS Act, and the concerns of customers in relation to bushfire safety, SA Power Networks has formed the view that the current condition of metered mains is an identifiable risk that can be prevented by SA Power Networks. The cost of the forecast capital expenditure associated with taking this preventative step is not grossly proportionate to that risk. Therefore undertaking this strategy is a reasonable step that SA Power Networks is obliged under its regulatory obligations and requirements to take at this point in time.

SA Power Networks' bushfire mitigation – metered mains forecast expenditure for the 2015-20 RCP is summarised in Table 7.11.

Table 7.11: SA Power Networks' bushfire mitigation – metered mains capital expenditure (June 2015, $ million)

Safety – Bushfire mitigation	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Metered Mains	1.2	2.5	2.5	2.6	1.3	10.1

[87] Powerline Bushfire Safety Taskforce, *'Final Report'*, 30 September 2011, page 23-24.
[88] EnergySafety WA, *Electrical Incident Report, Volume 1: Bushfire 180 Granite Road, Parkerville, Western Australia, 12 January 2014*, 2 December 2014.

More frequent asset inspections in BFRAs

Our proposed bushfire mitigation program also includes shifting to an asset inspection frequency of five years for all assets in BFRAs.

The forecast expenditure associated with this shift in the frequency of asset inspections in BFRAs is operating expenditure and has been discussed in Section 8.3 of this Revised Proposal.

However the reasons in support of that forecast operating expenditure are the same as the reasons in support of the other parts of our revised bushfire mitigation program. In particular, the shift to a five year asset inspection cycle in BFRAs is required in order to comply with our regulatory obligations. The five year inspection cycle represents a reasonable step to take in order to discharge our obligation to ensure that the distribution is safe and safely operated. It also reflects good electricity industry practice. This has been acknowledged by the AER.

Despite this fact the AER has determined that this is merely a change in business practice and SA Power Networks does not need additional funding in relation to this change.

This is not a change in business practice. SA Power Networks' business practice has always been to comply with its regulatory obligations and good electricity industry practice. What has changed in this case is not SA Power Networks' business practices but the steps that SA Power Networks needs to take in order to discharge its regulatory obligations and comply with good electricity industry practice.

When that change occurred is largely irrelevant. The AER has acknowledged that this is now 'good practice'. SA Power Networks has implemented this change during the 2014/15 regulatory year. It is likely that the change in the steps required to comply with our regulatory obligation actually occurred earlier in the 2010-15 RCP. What matters is that SA Power Networks must adopt this step now to comply with its regulatory obligation and SA Power Networks did not implement this step during or prior to the 2013-14 base year (ie the operating expenditure in the 2013/14 base year only included costs related to a 10 year inspection cycle for assets in BFRAs).

For further information of the proposed increase in asset inspections in BFRAs, refer to Section 8.13.

7.7 Augmentation: Safety – Bushfire Safer Places

In our Original Proposal, our undergrounding for bushfire safety program (including bushfire safer places (**BSPs**)) formed part of our bushfire mitigation program.

In its Preliminary Determination, the AER did not accept our forecast undergrounding for bushfire safety program (including BSPs) capital expenditure of $128.6 (June 2015, $ million) and excluded this forecast expenditure from its substitute estimate.

SA Power Networks does not accept the AER's Preliminary Determination in relation to this expenditure and has included a revised forecast of $26.8 (June 2015, $ million) in this Revised Proposal to reinforce the supply of electricity to 12 Country Fire Service (**CFS**) designated BSPs. Our reasons are explained below.

7.7.1 Rule requirements

Clause 6.5.7(a) of the NER provides that SA Power Networks must submit a building block proposal that includes a forecast of the capital expenditure it requires to meet the capital expenditure objectives for the 2015-20 RCP. This includes capital expenditure objective relating to the maintenance of the quality, reliability and security of SA Power Networks' SCS.

The AER **must** accept the proposed capital expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied the forecast capital expenditure for the 2015–20 RCP reasonably reflects the capital expenditure criteria.

Furthermore, in assessing the expenditure required to comply with all of these obligations, the AER is required to have regard to

> *'the extent to which the forecast includes expenditure to address the concerns of electricity consumers identified by the DNSP in the course of its engagement with electricity consumers'* [89] *(**Consumer Engagement Factor**).*

7.7.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks included forecast capital expenditure of $128.6 (June 2015, $ million) for undergrounding approximately 135 km of targeted high risk power lines in high bushfire risk areas (**HBFRAs**). This forecast included an amount of $26.6 (June 2015, $ million) to underground electricity supplies to 12 targeted CFS designated BSPs.

The undergrounding for bushfire safety program formed part of SA Power Networks' bushfire mitigation program, a program we consider is necessary in order to comply with good electricity industry practice.

SA Power Networks explained that due to the high cost of broad scale undergrounding, we proposed to limit the replacement of bare conductors with underground cables to supply BSPs, and targeted areas of high risk power lines in HBFRAs in combination with our other bushfire mitigation initiatives (such as replacing RAGs with surge arrestors).

Through our comprehensive CEP and subsequent WTP analysis, we found that SA Power Networks' customers were willing to contribute $12 per annum through their annual electricity bills to improve

[89] NER clause 6.5.6(e)(5A).

bushfire safety through dedicated programs to place 135 km of high risk overhead power lines in HBFRAs underground in conjunction with our proposed vegetation management initiatives.

7.7.3 AER's Preliminary Determination

In its Preliminary Determination, the AER rejected our proposed forecast capital expenditure for the undergrounding for bushfire safety program because it was not satisfied that the program:

- is required to maintain the reliability and safety of the network; and
- would be a prudent and efficient investment in the network.

The AER expressed concern that SA Power Networks relied on the WTP survey findings conducted by the NTF Group to support the $128.6 (June 2015, $ million) undergrounding component of the bushfire mitigation program, rather than undertaking a traditional cost benefit analysis methodology:

> *'SA Power Networks' business case is qualitative and other supporting material it has provided does not properly evaluate the costs versus the benefits of the program. This includes information it provided on consumers' willingness-to-pay for undergrounding powerlines in High Bushfire Risk Areas (HBRAs).'*[90]

The AER considered the WTP survey and its findings do not demonstrate that the bushfire undergrounding program is a prudent and efficient investment. This initial assessment was further informed by the AER's interpretation of its consultant's, Oakley Greenwood, peer review of the WTP survey and findings. In relation to SA Power Networks' undergrounding for bushfire safety program in particular, Oakley Greenwood considered SA Power Networks should have considered adopting service offerings with higher acceptance, such as *'the bundle comprising zero km of undergrounding in HBRAs and BFRAs and 2.5 per cent vegetation management.'*[91]

In relation to the WTP methodology applied to our undergrounding for bushfire safety program, the AER formed the view that the survey was presented in such a manner that it may have influenced participants:

> *'Information was also lacking around how survey participants would be affected by the cost of the undergrounding program. If survey participants are not adequately informed as to the outcome of possible choices in a WTP survey, the findings are less likely to reflect customers' views as to their willingness-to-pay.'*[92]

The AER also stated that:

> *'On the issue of the WTP survey lacking representation of SA Power Networks' customer base, we note that survey participants were only residential customers. Given that most business customers are likely to be located in metropolitan areas which are less prone to bushfires, the WTP survey may overestimate support for undergrounding in HBRAs.'*[93]

The AER acknowledged SA Power Networks' efforts to engage with electricity customers through our CEP and WTP survey to identify and determine preferences on the undergrounding aspects of the bushfire mitigation program. However, given its concerns regarding our CEP and subsequent WTP

---

[90] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 6-50.
[91] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-58.
[92] Ibid.
[93] Ibid.

survey and findings, it placed greater weight on submissions received from other stakeholders that were not supportive of the program.

When forming its decision in relation to the undergrounding bushfire safety program, the AER also considered:

> *'….there are alternative funding options for the [undergrounding] program, namely as a Power Line Environment Committee (PLEC) project, and this would likely involve a more consultative, collaborative approach then what was taken in developing SA Power Networks' current proposal.'* [94]

7.7.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks does not accept the AER's Preliminary Determination in relation to the bushfire safety program (including BSPs) because the AER has not had sufficient regard, as required by the Consumer Engagement Factor, to our CEP which reflects the strong community safety concerns vocalised by South Australian electricity customers.

In its Preliminary Determination, the AER noted our efforts to engage with our customers on bushfire issues but then effectively dismissed the findings of our demonstratively robust CEP, instead giving greater weight to a very limited number of stakeholder submissions (despite those submissions having raised either unsubstantiated, or technically lacking, criticisms).

As discussed at length in Chapter 3 of this Revised Proposal, the AER's decision to reject our CEP findings is fundamentally erroneous. Our CEP has demonstrated that our customers value safety very highly and want (and expect) SA Power Networks to undertake additional steps and programs of work to ensure ongoing community safety in HBFRAs.

Through our CEP we identified our customers rated the top three community safety and reliability initiatives as:

- inspecting, maintaining and upgrading the network;
- bushfire prevention activities; and
- hardening the network against lightning and storms.

From our Stage 1 workshop that was independently facilitated by Deloitte, the following was identified:

> *'Ensuring CFS bushfire safe precincts have continuous power supply was an essential activity to be undertaken, according to 83% of participants. Power was seen as vital during emergency situations, with participants suggesting that continual and reliable power would provide a sense of community safety.*
>
> *Of the three bushfire management activities, ensuring CFS bushfire safe precincts have continuous power supply was assigned the highest importance. Although only 15% of participants had previously heard of CFS bushfire safe precincts, on learning about them 84% stated that ensuring these locations have a constant supply of power is an essential activity to manage the risk and impact of bushfires*

[94] Ibid.

to the community. Residential participants placed the greatest importance on all three activities compared to all other groups.'[95]

The AER expressed concerns that our WTP was not representative and therefore potentially overstated. This is incorrect and is addressed in Chapter 3. The sample of 895 respondents deployed by The NTF Group in the targeted WTP research was representative of South Australian electricity customers because the sample was post-weighted and correlated to Australian Bureau of Statistics (**ABS**) data to ensure it was representative in terms of both demographics and household solar PV penetration.

Some stakeholder submissions, along with the AER, were of the opinion that the PLEC program would be a more consultative and collaborative approach to addressing reinforcement of supply to BSPs. However, SA Power Networks has sought advice from ESCoSA on this issue and has been advised as follows:

> *'PLEC funds are directed to projects of general community benefit where the benefits pertain to the aesthetics of an area and/or road safety.*
>
> *As set out in the PLEC Charter, the purpose of undergrounding work that is the subject of undergrounding programs is to improve the aesthetics of an area for the benefit of the general community having regard to road safety and the provisions for electrical safety pursuant to the Electricity Act 1996.*
>
> *Undergrounding work cannot, unless the Minister determines, be included in a draft undergrounding program unless the Council of each area concerned has agreed to contribute to the cost of such work on the basis of $1 for every $2 of the cost of the work to be carried out at the expense of the Network Licensee.'*

Further:

> *'Bushfire-safe areas, as submitted by SA Power Networks in its regulatory reset proposal, could certainly be proposed to PLEC by SA Power Networks but they would need to be financially supported by the council(s) involved and would also need to have met the PLEC criteria, ie to be worthy of PLEC funding. Given the nature of projects that are currently under consideration, SA Power Networks' proposed bushfire-safe areas may not rate as highly in terms of aesthetic benefits.'*[96]

To reiterate, the primary driver behind the undergrounding of supplies to BSPs is to maintain electricity supply to these precincts for as long as possible during bushfire events. A secondary benefit is the ability to maintain power during catastrophic weather events. In most cases the undergrounding of power lines will be along subsidiary roads, therefore offering minimal aesthetic and road safety benefits for the broader community. Additionally, as ESCoSA highlighted, PLEC programs are initiated by the respective Councils and are subject to certain assessment criteria, primarily addressing aesthetics. Furthermore, the lead time to complete an individual PLEC project is in the order of two to three years from the date of the initial application.

The BSP program is aimed at providing community safety in the form of a more secure electricity supply in country regions that are at high risk during bushfire events. SA Power Networks is of the opinion that the AER's preliminary decision is biased to metropolitan customers because the majority

[95] Deloitte, *SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report*, July 2013, p 30.
[96] Email correspondence with ESCOSA.

of the CEP initiated programs were to benefit country customers and yet the AER did not accept any of these programs in its Preliminary Determination.

7.7.5 Revised Proposal

SA Power Networks' revised undergrounding in bushfire safety program relates to undergrounding 12 designated BSPs only and is forecast at $26.8 (June 2015, $ million).

This BSP program has been removed from the 'bushfire mitigation' umbrella in this Revised Proposal because the driver of the program is community safety, not bushfire mitigation.

Notwithstanding the significant level of support for undergrounding high risk power lines in HBFRA's that was evident in various aspects of our customer engagement, we have noted some queries raised as to whether there may be more cost-effective approaches to achieving an equivalent outcome. On balance, despite the support for such options, we accept the desirability of additional customer engagement to explore the opportunity for a greater consensus and further assess alternative options, prior to consideration of similar proposals in the future.

SA Power Networks' bushfire safer places forecast capital expenditure for the 2015-20 RCP is set out in Table 7.12.

Table 7.12: SA Power Networks' bushfire safer places capital expenditure (June 2015, $ million)

Safety	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Bushfire safer places	5.6	5.8	3.8	6.4	5.1	26.8

7.8 Augmentation: Safety – Back-up protection

In our Original Proposal, our proposed back-up protection program formed part of our bushfire mitigation program.

The AER did not accept our forecast back-up protection capital expenditure of $18.4 (June 2015, $ million) and excluded this forecast expenditure from its substitute estimate in its Preliminary Determination.

SA Power Networks does not accept the AER's Preliminary Determination in relation to this program and, consistent with our Original Proposal, we include a revised forecast of $18.6 (June 2015, $ million) in this Revised Proposal to address sections of the network in country locations where the back-up protection does not currently comply with our regulatory obligations and requirements. Our reasons are explained below.

7.8.1 Rule requirements

Clause 6.5.7(a) of the NER provides that SA Power Networks must submit a building block proposal that includes a forecast of the capital expenditure it requires to meet the capital expenditure objectives for the 2015-20 RCP. This includes the capital expenditure objective that is related to complying with all applicable regulatory obligations or requirements associated with the provision of SCS and maintaining the quality, reliability and security of SA Power Networks' SCS.

The AER must accept the proposed capital expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied the forecast capital expenditure for the 2015–20 RCP reasonably reflects the capital expenditure criteria. In making this assessment the AER must have regard to the capital expenditure factors.

In addition, we note that clause S5.1.9 of the NER, and subclauses (c) and (f) in particular, sets out SA Power Networks' obligations in relation to protection systems and fault clearance times:

> *'(c) Subject to clauses S5.1.9(k) and S5.1.9(l), a Network Service Provider must provide sufficient primary protection systems and back-up protection systems (including breaker fail protection systems) to ensure that a fault of any fault type anywhere on its transmission system or distribution system is automatically disconnected in accordance with clause S5.1.9(e) or clause S5.1.9(f).*
>
> *(f) The fault clearance time of each breaker fail protection system or similar back-up protection system of a Network Service Provider must be such that a short circuit fault of any fault type that is cleared in that time would not damage any part of the power system (other than the faulted element) while the fault current is flowing or being interrupted.'*

SA Power Networks is also required, under the conditions of its Distribution Licence and section 25 of the *Electricity Act,* to comply with its ESCoSA approved SRMTMP. Section 2.3.3 of the SRMTMP provides that we must comply with Network Directive – Distribution Protection Philosophy ND J1 which addresses certain safety and technical matters.

7.8.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks included a forecast capital expenditure of $18.4 (June 2015, $ million) in its bushfire mitigation program to address sections of the network in country locations where the back-up protection does not currently comply with clauses S5.1.9(c) and (f) of the NER and ND J1.

Back-up protection is intended to operate when a system fault is not cleared by the main protection because of a failure or inability of the main protection to operate. Adequate back-up protection is defined as being able to detect any credible HV fault on a feeder and clear the fault within an acceptable timeframe should any one protection device or fault breaking device fail.

Adequate back-up protection exists in the greater metropolitan region but is deficient in many rural areas due to the inherent design of rural networks. Following the findings of the VBRC, SA Power Networks undertook a review of our protection systems in rural areas. In 2013, SA Power Networks identified a large part of its rural network as having inadequate back-up protection. At the same time we were experiencing an increase in the failure of protection devices in rural areas.

If a protection device fails to operate and the fault remains, it presents a significant public safety and fire risk and damage to network assets can result. Due to these significant risks, SA Power Networks commenced the back-up protection program in 2014 to address the highest risk assets, and proposes to continue the program over the 2015-20 and 2020-25 RCPs.

7.8.3 AER's Preliminary Determination

In its Preliminary Determination, the AER did not accept our bushfire mitigation program which included our safety – back-up protection program. Whilst the AER did not specifically mention our proposed back-up protection program in its Preliminary Determination, it generally stated that:

> *'We note, in our reasons below, the specific areas where sufficient supporting material was not provided or the evidence submitted did not reasonably demonstrate the program satisfied the criteria.*
>
> *In summary, we consider that:*
>
> - *SA Power Networks' proposed capex is not required to maintain the reliability and safety of its network.*
> - *SA Power Networks has not provided sufficient evidence of increased bushfire risk from ignition by power lines in SA. There has also been no change to regulations and/or safety standards related to bushfire risk that would justify additional expenditure.*
> - *SA Power Networks' proposed capex is not a prudent and efficient investment.*
> - *SA Power Networks have not undertaken a cost benefit analysis of the program. SA Power Networks' business case is qualitative and other supporting material it has provided does not properly evaluate the costs versus the benefits of the program. This includes information it provided on consumers' willingness-to-pay for undergrounding powerlines in High Bushfire Risk Areas (HBRAs).'*[97]

7.8.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks does not accept the AER's Preliminary Determination in relation to this program. Apart from it being unclear whether the AER actually turned its mind to the back-up protection program, the associated forecast expenditure is required to satisfy our regulatory obligations under subclause S5.1.9(c) and (f) of the NER and ND J1, and to maintain the safety of the distribution system.

[97] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 6-50.

The inherent design of our rural network means SA Power Networks does not have sufficient back-up protection systems to ensure that a credible fault of any type anywhere on our rural distribution network is automatically disconnected as required by clause S5.1.9(c) of the NER.

For example, short circuit faults on our 19kV SWER networks generally cannot be detected by the protective device on the supply side of the source (eg the transformer fuse), due to inadequate sensitivity. Consequently, when the primary protection device fails (on the supply side) the fault will remain energised until sufficient supply side assets have burnt down, triggering a bigger fault closer to the supply side protective device. During this period steel poles will remain energised posing a significant risk to the public and animals. The burning down of conductors, and catastrophic failure of supply side transformers, have started fires.

Furthermore, SA Power Networks has identified that the fault clearance time of our protection systems or similar back-up protection system on many parts of our rural distribution network cannot clear a short circuit fault fast enough to prevent damage to our network while the fault current is flowing or being interrupted as required by clause S5.1.9(f) of the NER.

For example, short circuit faults on our 11kV or 19kV networks supplied by small HV/HV transformers (33/11kV 33/19kV) may be cleared very slowly or not at all by the source transformer fuse, with similar consequences mentioned in the previous example above.

SA Power Networks' SRMTMP references ND J1. Section 6.1 of ND J1 explicitly states that:

> *'[e]lectrical protection and earthing systems must be designed, installed, operated and maintained to safely manage abnormal electricity network conditions likely to significantly increase the risk of personal injury or significant property damage.' Section 6.2 of ND-J1 states that SA Power Networks must '[p]rovide backup protection to the adjacent portion of the HV network, where duplicated or 2 sets of protection are not [currently] used.' Further, section 6.3 of ND-J1 states that '[t]he protection system must comply with the requirements of the Electricity Technical Regulations and the National Electricity Rules.'*

ND J1 came into effect in 2013 and SA Power Networks undertook a detailed assessment of our protection systems at that time which found a significant portion of the rural network did not comply. In response to those findings, SA Power Networks commenced remediating the back-up protection on our rural network using a risk based prioritisation in 2014.

In addition to the above, it is SA Power Networks' duty to take reasonable steps to ensure that our distribution system is safe and safely operated (in accordance with section 60(1) of the *Electricity Act*) and to maintain and operate our facilities in accordance with good electricity industry practice (in accordance with clause 5.2.1(a) of the NER). These duties require us to have regard to applicable standards of safety to ensure that the distribution system is safe and safely operated and is maintained and operated in a manner that is consistent with the degree of skill, diligence, prudence and foresight expected from Australian electricity distribution system operators.

In its Preliminary Determination, the AER inferred that we should have undertaken a cost benefit analysis of the program.

As stated in Chapter 3 of this Revised Proposal, SA Power Networks' activities are governed by the *Work Health and Safety Act 2012* (SA) (**WHS Act**) and SA Power Networks owes a non-delegable duty (in respect of health and safety to both its workers and all other persons who may be affected by assets within its management) to, <u>so far as is reasonably practicable</u>, ensure that its workplace is without risk to the health and safety of any person. In the context of dangers caused by its distribution system, SA Power Networks has a duty towards all 'other persons' in the vicinity of its distribution system under the WHS Act.

There is a clear presumption in the WHS Act in favour of safety ahead of cost. This is consistent with the rationale behind the notion of reasonable practicability. In the context of negligence, courts very rarely find that a reasonable person should not take measures solely because of their cost.

It is for this reason that the definition of 'reasonably practicable' in section 18 of the WHS Act provides that the cost of taking a control measure must be 'grossly disproportionate' to the risk it seeks to address before it will not be reasonably practicable to take that measure.

Therefore, in order to discharge its statutory health and safety duties, SA Power Networks is required to implement any control measures of which it is aware, provided that the cost of doing so is not grossly disproportionate to the risk it seeks to address. A typical (or standard) cost/benefit analysis is inappropriate when determining whether SA Power Networks is required to implement a particular control measure. The balancing exercise between safety and cost is weighted far more in favour of safety.

The AER expressed concern that our proposed bushfire mitigation program as a whole was not a prudent and efficient investment. In our view, the AER's concerns are unfounded. The back-up protection program is a prudent investment as it is being undertaken to comply with a regulatory obligations and to maintain reliability of supply on our rural network. The program is efficient, as the forecast expenditure is based on efficient historical costs.

7.8.5 Revised Proposal

Consistent with our Original Proposal, SA Power Networks' revised forecast for our back-up protection program is $18.6 (June 2015, $ million), as set out in Table 7.13.

The back-up protection program has been removed from the umbrella of our bushfire mitigation program in this Revised Proposal. Whilst the backup program is aligned with bushfire mitigation, the driver of this program is primarily to achieve compliance with our regulatory obligations and requirements related to back up protection, not bushfire mitigation.

For further information refer to Attachment G.5: *Protection compliance* – Back-up protection.

Table 7.13: SA Power Networks' forecast back-up protection capital expenditure (June 2015, $ million)

Safety	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Back-up protection	2.8	3.0	3.4	3.6	5.8	18.6

7.9 Augmentation: Reliability

In its Original Proposal, SA Power Networks outlined proposed expenditure forecasts for the following five reliability programs:

- Maintaining the network;
- Hardening the network;
- Low reliability feeders;
- Remote communities (Hawker and Elliston); and
- Micro-grid trial.

As noted earlier, the AER only included an allowance for expenditure relating to the maintaining the network program in its Preliminary Determination. We accept the AER's preliminary decision to include forecast expenditure for this core program for maintaining reliability of the network, but not its decisions to reject the forecast expenditure associated with the remaining four programs. Our response and revised proposals for these programs are outlined below.

7.9.1 Rule requirements

Clause 6.5.7(a) of the NER provides that SA Power Networks must submit a building block proposal that includes a forecast of the capital expenditure required to meet the capital expenditure objectives for the 2015-20 RCP. This includes capital expenditure required to comply with all applicable regulatory obligations or requirements associated with the provision of SCS and to maintain the reliability of SA Power Networks' SCS.

The AER **must** accept the proposed capital expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied the forecast capital expenditure for the 2015–20 RCP reasonably reflects the capital expenditure criteria. In making this assessment the AER must have regard to the capital expenditure factors.

In particular, in assessing the expenditure required to comply with all of these obligations, SA Power Networks is required to have regard to

> *'the extent to which the forecast includes expenditure to address the concerns of electricity consumers identified by the DNSP in the course of its engagement with electricity consumers'* [98] *(**Consumer Engagement Factor**).*

Reliability capital expenditure is required in order for us to maintain our reliability performance and comply with the Essential Services Commission of SA (**ESCoSA**) service standards for reliability set out in the South Australian Electricity Distribution Code (**EDC**) Compliance with the EDC is a condition of our Distribution Licence.

---

[98] Clause 6.5.6(e)(5A) of the NER.

7.9.2 SA Power Networks' Original Proposal

Hardening the network

SA Power Networks, in accordance with the current jurisdictional reliability service standard framework, is required to use its best endeavours to meet overall regional reliability targets. However, due to severe weather events, major event days (**MEDs**), our overall reliability performance has declined. Some customers are experiencing much worse performance during these events than the reliability targets set by ESCoSA and on average the increasing number and severity of these weather events has contributed an additional 60 minutes without supply to all customers per year in the 2010-15 RCP compared with the 2005-10 RCP.

Consistent with its historical approach, ESCoSA will focus on our performance during MEDs in the 2015–20 RCP. It is ESCoSA's expectation that our performance during MEDs and the associated severe weather events will not decline but improve. ESCoSA's Service Standard Framework requires ongoing regional and MED monitoring of SA Power Networks' reliability performance to ensure that any decline in performance is highlighted and addressed.

To mitigate the deterioration in our reliability performance attributable to MEDs, SA Power Networks proposed to harden our network in locations that are consistently affected by lightning and wind storms which resulted in MEDs.

As explained in Chapter 3 of this Revised Proposal, SA Power Networks undertook a comprehensive CEP prior to preparing its Original Proposal. Throughout our CEP, customers and stakeholders expressed support for programs aimed at:

- further protecting some parts of the network, particularly in regional areas which are more susceptible to damage from storms, especially lightning strikes; and
- upgrading and reinforcing the network where the network supply configuration to an area is susceptible to failure (eg single radial supply lines in rural and remote areas).

Furthermore, in their '*Climate extremes analysis for South Australian Power Network operations*' (set out in Attachment 10.2 to the Original Proposal), the Bureau of Meteorology (**BoM**) report predicted the trend in severe weather events is likely to continue. Consequently, SA Power Networks expects that overall reliability performance will continue to deteriorate unless the network's performance during severe weather events is addressed.

The 'hardening the network' program comprised a number of strategies to reduce the impact of the increased number and severity of severe weather events that result in MEDs, and return reliability performance closer to historic average levels for those customers affected by supply interruptions on MEDs.

The proposed hardening the network program included projects with one or more of the following initiatives:

- installing insulated overhead conductors;
- re-insulating sections of lines with lightning resistant insulators;
- installing fuse savers; and
- installing additional reclosers.

In our Original Proposal, SA Power Networks submitted a forecast capital expenditure of $17.0 (June 2015, $ million) for this program of works.

Low reliability feeders

Prior to the 2010-15 RCP, ESCoSA had a regime in place that provided monetary incentives to SA Power Networks to improve the performance of poor performing feeders. This regime was adopted because customers in general were willing to pay to improve the reliability to the worst served customers. Consequently, when establishing the 2010-15 Reliability Service Standard Framework, ESCoSA created a regime whereby SA Power Networks was required to publicly report on the worst performing 5% of feeders. The criterion for this was that a feeder's SAIDI exceeded 2.1 times the regional SAIDI average service standard target for two consecutive years.

Generally, poor performing feeders remain on this 'Low reliability feeders' list for one or two years until improvements are implemented. However, there are currently 31 feeders which supply small remote communities whose reliability levels have exceeded the 2.1 times regional SAIDI threshold for at least three consecutive years. These feeders have on average exceeded the service standard target by more than five times. Given that only a small number of customers are affected, the lower service levels that these customers experience do not contribute materially to the overall reliability performance outcomes of the region. This means that SA Power Networks is not incentivised under the STPIS to improve network reliability in these areas. However, we are required to report to ESCoSA on actions that we are taking to improve the reliability of supply to these areas.

The 31 distribution feeders (supplying approximately 3,900 customers) represent less than two per cent of the total number of feeders in our network. Of these 31 feeders, there are 24 feeders that have feasible reliability solutions similar to the hardening the network initiatives that can be implemented. For six of the remaining feeders, reliability issues can be addressed by managing reliability performance of the upstream network within the core reliability program. The other remaining feeder is considered suitable for a micro-grid trial. Once implemented, the proposed solutions will remove these feeders from the 'Low reliability feeders' list.

ESCoSA expects that feeders on the 'Low reliability feeder' list will not remain on that list for multiple consecutive periods. To this end, SA Power Networks' low reliability feeders program has been specifically developed to improve reliability performance of the 24 low reliability feeders and remove them from the 'Low reliability feeder' list.

In our Original Proposal, SA Power Networks submitted a forecast capital expenditure of $8.5 (June 2015, $ million) to remediate these low reliability feeders.

Remote communities (Hawker and Elliston)

In our Original Proposal, SA Power Networks proposed a specific program to remediate the distribution feeders supplying the townships of Hawker in the Flinders Ranges and Elliston on the Eyre Peninsula. The reliability performance of these feeders consistently and significantly exceeds the reliability targets for those regions.

Hawker experiences an average annual SAIDI of 1,339 minutes compared to the current target in the Electricity Distribution Code (**EDC**) for its geographical area of 425 minutes. Similarly, the average annual SAIDI for Elliston has been 1,512 minutes compared to the current target in the EDC for its geographical area of 425 minutes. These feeders have not been included in the 31 low reliability feeders identified in the low reliability feeder program discussed above.

The Hawker and Elliston program was developed as a direct result of customers' concerns raised in our CEP workshops held in regional locations. These workshops reaffirmed the requirement for a reliable supply comparable with other townships within their region.

In our Original Proposal, the forecast expenditure for this program was $2.4 (June 2015, $ million).

Micro-grid trial

In our Original Proposal, SA Power Networks proposed forecast capital expenditure of $2.8 (June 2015, $ million) to undertake a micro-grid trial to remediate one of our worst performing feeders (being one of the 31 low reliability feeders identified in the low reliability feeder program discussed above).

Using a combined distributed storage and centralised storage solution, this trial is aimed at improving the reliability performance to one of the worst served communities, Springton, so that this feeder's performance is no longer in the 'low reliability feeder' list. This is consistent with ESCoSA's expectation that customers' reliability performance would be restored closer to regional targets. It is SA Power Networks' intention to use this micro-grid trial as a template for future reliability remediation, or deferral of network augmentation, to other remote communities.

Investigating the opportunities presented by micro-grid technology is also consistent with a number of insights gained from our CEP, in particular:

- our customers' desire to improve service to the worst served customers, particularly those on long radial feeders, most likely to be affected by severe weather events;
- the need for SA Power Networks to remain up-to-date with new technologies and how these might integrate with the network and/or reduce costs; and
- that SA Power Networks ensures its network services support the development of its communities.

7.9.3 AER's Preliminary Determination

In its Preliminary Determination, the AER accepted our forecast capital expenditure of $28.1 (June 2015, $ million) for maintaining reliability (excluding MEDs), but it did not accept our capital expenditure forecasts for:

- **Hardening the network** - $17.0 (June 2015, $ million) to improve our overall performance to country communities during MEDs;
- **Low reliability feeders** - $8.5 (June 2015, $ million) to remediate our worst performing feeders;
- **Remote communities (Hawker and Elliston)** - $2.4 (June 2015, $ million) to remediate the power lines supplying these communities whose reliability performance consistently and significantly exceeds the reliability targets for their regions; and
- **Micro-grid trial** - $2.8 (June 2015, $ million) to conduct a micro-grid trial on one of the 31 worst performing feeders.

In general, the AER formed the view that the analysis underpinning these programs did not take into consideration how a MED is defined in the 2015-20 RCP where the calculation methodology will change from the Box-Cox methodology to the STPIS scheme standard IEEE methodology. Further, program-specific comments are noted below.

Hardening the network

In its Preliminary Determination, the AER stated:

> *'it is unclear whether SA Power Networks has taken into account the impact of the new definition of MEDs in its modelling of the hardening network program. This makes it difficult for us to be satisfied that the STPIS regime will not fund this program.'*[99]

[99] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 6-79.

On this basis, the AER did not accept our forecast capital expenditure of $17.0 (June 2015, $ million) to improve our overall performance to country communities during MEDs but the AER did invite us to provide more information in our Revised Proposal on whether our cost-benefit analysis of the hardening network program takes into account the new definition of MEDs.

Low reliability feeders

In its Preliminary Determination, the AER did not accept our capital expenditure forecast of $8.5 (June 2015, $ million) to improve the performance of our 24 worst performing feeders.

The AER formed the view that we did not provide any analysis to demonstrate that the value of customer reliability (**VCR**) consumer benefits realised by implementing this program will exceed the costs of the program.

The AER was not satisfied there was a positive cost benefit analysis, or that improving performance from the worst performing feeders would not otherwise be funded through the STPIS regime.

Remote communities (Hawker and Elliston)

In its Preliminary Determination, the AER did not accept our capital expenditure forecast of $2.4 (June 2015, $ million) to improve the reliability of supply to Hawker and Elliston.

Again, the AER formed the view that we did not provide any analysis to demonstrate that the VCR consumer benefits of this program will exceed the costs of the program:

> *'While SA Power Networks considers that this program utilises the most cost effective technology, it has not provided any cost-benefit analysis or other information to demonstrate the need or efficiency of the proposed expenditure. Based on this, we do not accept the proposed capex.'*[100]

Micro-grid trial

In its Preliminary Determination, the AER did not accept our capital expenditure forecast of $2.8 (June 2015, $ million) to conduct a micro-grid trial on one of our worst performing feeders.

The AER stated:

> *'We recognise that this is a trial, and therefore it is difficult to accurately quantify the likely benefits in terms of reliability. However, SA Power Networks proposes this program on the basis of reliability improvement rather than reliability maintenance. To allow for reliability improvement, we need to be satisfied that the proposed expenditure will encourage prudent and efficient outcomes and that it will not otherwise be funded through the STPIS regime.'*[101]

Given the AER was unclear how we calculated the impact of the micro-grid trial, it did not accept our forecast capital expenditure but the AER invited us to provide more information on the benefits of the micro-grid trial and how it fits within the suite of our proposed reliability improvement programs.

[100] AER, Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20, April 2015, p 6-81.
[101] AER, Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20, , April 2015, p 6-82.

SA Power Networks' response to AER Preliminary Determination

SA Power Networks accepts the AER's Preliminary Determination to include forecast expenditure for the core maintaining reliability program but does not accept its decisions to reject the forecast expenditure associated with the remaining four programs.

Submissions

SA Power Networks is concerned with the weight the AER has given to a number of submissions to our Original Proposal that were critical of our proposed reliability improvement programs.

These submissions expressed concern with our proposed reliability improvement programs when, overall, customers are satisfied with current levels of network reliability.

While SA Power Networks is maintaining underlying reliability performance, the resulting reliability outcomes during MEDs in the 2010-15 RCP were poor. As a result, all customers experienced, on average, an additional 60 minutes of supply interruptions per year in the 2010-15 RCP compared with the 2005-10 RCP.

The submissions on our Original Proposal concerning reliability are focused on underlying reliability and are not consistent with the CEP outcomes which support actions to address reliability during severe weather events and therefore the AER should give no weight to those submissions that expressed concerns.

Findings of our CEP

SA Power Networks is also concerned at the little (if any) weight that the AER gave to outcomes from our CEP which support these programs.

As explained in Chapter 3 of this Revised Proposal, the obligation of the AER to 'have regard' to a factor means that the AER must treat that factor as a fundamental element of its decision.[102] The AER cannot simply note that such concerns have been identified and discard them.[103] It must treat the consideration of these concerns (and the extent to which forecast expenditure addresses them) as a central element of its decision.[104]

In promulgating the Consumer Engagement Factor, the AEMC stated that (emphasis added):

> *'Finally, a factor was added that requires the AER to have regard to the extent to which NSPs have considered what consumers seek. NSPs should be engaging with consumers in preparing their regulatory proposals and should factor in the needs and concerns of consumers in determining, for example, their capex programs. <u>What consumers want and are prepared to pay for, whether in terms of reliability or some other element</u>, will assist in showing what is efficient. The more confident the AER can be that consumer's concerns have been taken into account, the more likely the AER could be satisfied that a proposal reflects efficient costs.'*[105]

[102] R Hunt; ex parte Sean Investments Pty Ltd [1979] 180 CLR 332 at 329; R v Toohey; ex parte Meneling Station Pty Ltd [1982] HCA 69, per Gibbs CJ at [5], per Mason J at [13]; Re Michael; ex parte Epic Energy (WA) Nominees Pty Ltd [2002] WASCA 231 at [55]; Telstra Corporation Limited v ACCC [2008] FCA 1758 at [105]; Telstra Corporation Limited v Australian Competition Tribunal [2009] FCAFC 23 at [267]; Re Application by EnergyAustralia [2009] ACompT 7 at [16].
[103] East Australian Pipeline Pty Ltd v ACCC [2007] HCA 44 at [52].
[104] Telstra v ACCC [2008] FCA 1758 at [52].
[105] AEMC, Economic Regulation of Network Service Providers, Final Rule Determination, 29 November 2012, p 101.

Our robust and representative CEP identified that 88% of customers supported further protecting the network to harden against lightning and storms, with 91% of metropolitan and regional customers supporting further protecting the network. This demonstrates that our customers want further protection of the network.

This, coupled with the fact that the NER were specifically amended to require the AER to have regard to this additional Consumer Engagement Factor and ESCoSA's expectation that our performance during MEDs and severe weather events will improve over the 2015-20 RCP, means that significant weight should be given by the AER to our CEP findings in relation to reliability.

Hardening the network

We do not accept the AER's preliminary decision to reject the proposed expenditure for our hardening the network program.

As part of this program, SA Power Networks is proposing to harden targeted sections of 78 power lines (both sub-transmission and distribution) against storms. The calculated reliability performance impact of the hardening the network program is summarised in Table 7.14.

Table 7.14: Analysis of impacts of the hardening of the network program

2010-2015 RCP	Do nothing	Post program	Impact
Overall Av. SAIDI (incl. MEDs) (minutes)	231.5	214.6	16.9
Underlying Av. SAIDI (excl. MEDs) (minutes)	161.1	162.6	(1.5)
Overall Av. SAIFI (incl. MEDs) (number)	1.718	1.644	0.074
Underlying Av. SAIFI (excl. MEDs) (number)	1.477	1.473	0.004
Total number of MEDs[106] (number)	20	16	(4)
STPIS Av. Net benefit (% pa)	0	(0.06)	(0.06)

From a customer perspective, the hardening the network program has a net customer Value of Customer Reliability (**VCR**) benefit in the order of $12 million p.a., noting that we assume in our conservative modelling that customer will only receive 50% of these benefits[107] resulting in a net present benefit of $53.4 million (NPV = +$53.4 million over 35 years), using VCR as an indicator of the value of reliability to customers. Further details in relation to this analysis can be found in Attachment G.6: *Reliability – Hardening the network.*

[106] Based on the standard IEEE exclusion methodology.
[107] That is, we have applied a conservative discount of 50% to the forecast customer VCR benefits in our modelling.

Whilst there is no material benefit to SA Power Networks in undertaking this program, customers supplied by the 78 power lines will experience improved overall network performance during similar severe weather events in their locality.

The hardening the network program would have resulted in four days which were previously classified as MEDs no longer being classified as MEDs. Consequently, the underlying STPIS performance would have declined if this program of works had been completed during the 2010-15 RCP. This would have resulted in a reduction in annual revenue of -0.06%.

Low reliability feeders

We do not accept the AER's preliminary decision to reject the proposed expenditure for our low reliability feeders program. There are some communities on the worst performing feeders list that experience reliability that is more than ten times worse than ESCoSA's regional targets. This is unacceptable and must be addressed in the 2015-20 RCP.

The AER requested further information on whether SA Power Networks' cost-benefit analysis of the worst performing feeder program takes into account the new definition of MEDs. SA Power Networks confirms the standard IEEE exclusion method was used to calculate MEDs, not the superseded Box-Cox method.

Detailed analysis has been undertaken to determine the likely effect of the proposed remediation works on the 24 worst performing feeders. The analysis was based on forecasting the proposed SAIDI and SAIFI changes on those communities and then subtracting the forecast performance from the actual performance over the period from 2009/10 to 2013/14. The findings were then assessed against the projected STPIS impacts. The results of this analysis are summarised in Table 7.15.

Table 7.15: Analysis of impacts of the low reliability feeder program

	Do nothing	Post program	Impact
Overall Av. SAIDI (incl. MEDs) (minutes)	231.5	230.5	0.9
Underlying Av. SAIDI (excl. MEDs) (minutes)	161.1	160.5	0.7
Overall Av. SAIFI (incl. MEDs) (number)	1.718	1.715	0.003
Underlying Av. SAIFI (excl. MEDs) (number)	1.477	1.474	0.003

Based on our modelling using the standard IEEE exclusion method (not the superseded Box-Cox method), it is forecast that SA Power Networks will marginally benefit from the STPIS with an annual revenue increase of +0.05% per annum. However, this benefit will be offset by the financial penalties from the hardening the network program (ie 0.06%). The impact on reliability from all improvement programs is discussed further under *Combined impact of reliability improvement programs* below.

In its Preliminary Determination, the AER was not satisfied that there is a positive VCR cost-benefit for this program. Assuming benefits to customers are progressively realised over the 2015-20 RCP and then continue for another 30 years, the low reliability feeders program has a financially neutral outcome (ie the benefits are $0.1 million less than the cost), based on the latest AEMO VCR values. Further details in relation to this analysis can be found in Attachment G.7: *Low reliability feeders*.

Given the outcome of the low reliability feeders program is financially neutral, SA Power Networks is of the view that it is unacceptable for those customers supplied by the 24 worst performing feeders to continue to be disadvantaged by reliability levels significantly below regional service targets. This is consistent with the findings from our CEP and ESCoSA's expectation that the worst performing feeder reliability performance should not deteriorate further, but rather return to the mandated regional targets.

Remote communities (Hawker and Elliston)

We do not accept the AER's preliminary decision to reject the proposed Hawker and Elliston reliability improvement program and reiterate that:

- the AER has, in our view, given little or no weight to the outcomes from our CEP;
- the AER's Preliminary Determination disadvantages rural customers, given that many of our rural customers are experiencing significantly poorer service compared to metropolitan and regional areas of the State; and
- SA Power Networks confirms the standard IEEE exclusion method was used to calculate MEDs, not the superseded Box-Cox method.

Detailed analysis has been carried out to determine the likely effect of these projects in all of the aspects described above. This analysis was based on forecasting the proposed SAIDI and SAIFI changes for Hawker and Elliston and then subtracting the forecast performance from the actual performance over the period from 2009/10 to 2013/14. The findings were then assessed against the projected STPIS impacts. The results of this analysis are summarised in Table 7.16.

Table 7.16: Analysis of impacts of the remote communities program

	Do nothing	Post program	Impact
Overall Av. SAIDI (incl. MEDs) (minutes)	231.5	231.1	0.4
Underlying Av. SAIDI (excl. MEDs) (minutes)	161.1	160.8	0.3
Overall Av. SAIFI (incl. MEDs) (number)	1.718	1.717	0.001
Underlying Av. SAIFI (excl. MEDs) (number)	1.477	1.476	0.001

Based on our modelling using the standard IEEE exclusion method (not the superseded Box-Cox method), it is forecast that SA Power Networks will marginally benefit from the STPIS with an annual revenue increase of +0.02% p.a. However, this would be offset by the financial penalties from the hardening the network program. The impact on reliability from all improvement programs is discussed further under *Combined impact of reliability improvement programs* below.

In its Preliminary Determination, the AER highlighted that SA Power Networks did not provide a cost benefit analysis for this program. We have undertaken a cost benefit analysis which indicates that, assuming benefits to SA Power Networks are progressively realised over the 2015-20 RCP and based on the latest AMEO VCR values, the NPV is -$1.7 million. The present value of the capital investment required to implement the program exceeds the present value of the expected benefits by $1.7 million. It is therefore not financially viable for SA Power Networks to fund this capital investment through traditional capital expenditure mechanisms. However, the NPV of the benefits less the costs to customers over a 35 year timeframe is positive at $0.5 million. Refer to Attachment G.8: *Reliability – Poorly served communities* for further details of this analysis.

The reason why the VCR benefit is not positive is because of the small number of customers being targeted and the radial nature of their supply. SA Power Networks is of the view that it is unacceptable for Hawker and Elliston, two tourism hubs, to be disadvantaged with electricity supply reliability levels that are significantly below regional targets. This is consistent with the findings of our CEP and ESCoSA's expectation that our performance during MEDs and severe weather events will not decline but improve in order to meet mandated regional targets in the 2015-20 RCP.

Micro-grid trial

We do not accept the AER's preliminary decision to reject the proposed expenditure for our micro-grid trial.

The objective of the micro-grid trial is to enhance SA Power Networks' understanding of the costs (both capital and operational) and the broader benefits of micro-grid technology. The outcome of this trial will assist SA Power Networks to assess other micro-grid deployments to determine where they are most likely to be effective and cost efficient.

If a micro-grid can provide significantly improved reliability for the customers affected at similar cost to conventional solutions, or where conventional solutions would not be effective, it may be justified from a customer service perspective. However, the trial will also review whether micro-grids can:

- provide an alternative augmentation option as well as providing voltage support and renewable energy integration;
- provide a feasible option for areas identified as bushfire safer places that may be disconnected from the main electricity grid during a bushfire event; and
- be cost effective in providing electricity in 'edge-of-grid' applications where the construction of a long grid connection may prove very costly.

The AER received a stakeholder submission[108] which suggested that we should delay our reliability improvement programs for hardening the network and improving low reliability feeders, pending the outcome of the trial micro-grid solution.

Micro-grids may offer an effective solution on a limited number of low reliability feeders where existing traditional solutions are not effective or are cost prohibitive. However, it should be noted that micro-grid battery storage (at this point in time) can only support supply of electricity for up to four hours. This means a micro-grid would only benefit two of the 31 worst performing feeders because most low reliability feeders have an average interruption duration of greater than four hours.

[108] SA Council of Social Services, *Submission to the Regulatory Proposal 2015–20*, January 2015.

While micro-grid technologies will be further evaluated as potential solutions to some network constraints, they are not currently a viable solution to all, or even the majority of, low reliability feeder performance issues.

Any delay in implementing the proposed hardening of the network and low reliability feeder programs will not support SA Power Networks' ability to manage the service to the worst served customers and will further exacerbate customers experiencing similar or deteriorating performance. This expenditure is considered prudent to manage the risks associated with the increasing severity and frequency of severe weather events, as predicted by the BoM, and to arrest the associated decline in performance and customer service on MEDs.

Given that lightning and wind are major causes of outages during MEDs, it is likely that the current poor performance on MEDs will continue or even deteriorate over the 2015-20 RCP, unless work is undertaken to manage the performance and harden the network against lightning and storms as proposed by SA Power Networks.

The micro-grid solution would not be considered to be a cost efficient or technically effective solution for hardening the network and for the majority of the low reliability feeders, as customers would incur significantly higher costs with limited benefits if this solution were to be implemented.

In line with the BoM predictions, it can be expected that the number of low reliability feeders and worst served customers affected would also increase particularly as SA Power Networks has observed a marked deterioration in performance of the network during MEDs since 2010. This has been reported in ESCoSA's '*Performance of SA Power Networks 2013-14.*'[109]

In its Preliminary Determination, the AER recognised the micro-grid solution was a trial and that it was therefore difficult to accurately quantify the likely benefits in terms of reliability. To allow for reliability improvement, the AER needed to be satisfied that the proposed expenditure was not funded through the STPIS regime. The modelled benefit to SA Power Networks from the STPIS regime is a 0.01% revenue increase which is off-set by the hardening of the network revenue decrease.

Detailed analysis has been undertaken to determine the likely effect of the proposed remediation works using a micro-grid solution on the selected worst performing feeder (Springton). The analysis was based on forecasting the proposed SAIDI and SAIFI changes on those communities and then subtracting the forecast performance from the actual performance over the period from 2009/10 to 2013/14. The findings were then assessed against the projected STPIS impacts. The results of this analysis are summarised in Table 7.17.

[109] See: http://www.escosa.sa.gov.au/library/20141127-Energy-AnnualPerformanceReport2013-2014-ElectricityDistribution-Report2.pdf.

Table 7.17: Analysis of impacts of the micro-grid trial if the micro-grid had been in place for the period from 1 July 2009 to 30 June 2014

	Without Micro-grid	With Micro-grid
Overall Av. SAIDI (excl. MEDs) (minutes)	19.5 hrs pa	8.1
Overall Av. SAIFI (excl. MEDs) (number)	7.0 pa	1.3

Assuming that, collectively, the additional STPIS benefit provides a reasonable surrogate for the value to customers of the increased reliability, this allows the net present value of the micro-grid trial project to be assessed. Assuming benefits continue at the stated value for 35 years, the NPV is -$1.7m and would therefore not be considered financially viable for SA Power Networks on its business case alone.

Based on our modelling using the standard IEEE exclusion method (not the superseded Box-Cox method), we are likely to marginally benefit financially from the STPIS (+0.01% p.a.). Again, this would be largely offset by the financial penalties from the separate hardening the network project.

For further details of this analysis refer to Attachment G.9: *Reliability – Micro-grid trial*.

Combined impact of reliability improvement programs

In its Preliminary Determination, the AER requested further information on whether SA Power Networks' cost-benefit analysis of the hardening the network program takes into account the new definition of MEDs.

SA Power Networks confirms the standard IEEE exclusion method was used to calculate MEDs, not the superseded Box-Cox method.

Table 7.18 provides forecasts of the average annual overall impact on SAIDI and SAIFI, and the impact on SAIDI and SAIFI excluding MEDs, as a combined result of our proposed reliability programs (including the hardening the network, low reliability feeders, Hawker-Elliston and micro-grid trial programs).

Table 7.18: Combined reliability programs impact on SAIDI and SAIFI

Reliability improvement pa	Hardening the network	Low reliability feeders	Remote communities	Micro-grid	Total
Overall SAIDI (minutes)	16.89	0.94	0.35	0.12	**18.31**
Overall SAIFI (number)	0.074	0.003	0.001	0.001	**0.079**
Underlying SAIDI (excl MEDs) (minutes)	(1.48)	0.68	0.32	0.12	**(0.36)**
Underlying SAIFI (excl MEDs) (number)	0.004	0.003	0.001	0.001	**0.008**

If these programs had been implemented for the entirety of the 2010-15 RCP, our analysis indicates the average overall annual SAIDI (including MEDs), would have been 18.3 minutes lower (being a better outcome for customers). This is less than one third of the average 60 minute increase that all customers have experienced in the 2010-15 RCP.

Further, we note that 15.2 minutes of those 18.3 minutes would have been associated with MEDs. Our analysis demonstrates that four MEDs in the analysed period would no longer be classified as MEDs if these reliability programs had been implemented. The average impact of these four days no longer being classified as MEDs would slightly increase (worsen) the underlying SAIDI (excluding MEDs) performance by 3.5 minutes.

However, combining the 3.1 minute improvement (18.3 minus 15.2 minutes) with the 3.5 minute decline, results in an overall decline[110] in our underlying reliability performance of 0.4 minutes per year.

That is, based on our analysis, the combined programs will improve the experience of some of our worst served customers, in line with their preferences, but there will be no benefit to SA Power Networks because there will be no improvement in the underlying reliability performance.

Overall, the proposed expenditure for the hardening the network, low reliability feeders and Hawker-Elliston programs has a net present value over a 35 year period to customers of $54 million, using the latest VCR values from AEMO.

The overall STPIS outcome from implementing the three proposed expenditure programs is neutral with potential for a slight positive outcome of about 0.02% of revenue. (If all programs had been in place for the full 2010-15 RCP, the overall impact on the STPIS is a marginal increase of 0.02% of revenue per annum. This is equivalent to $0.182 million per year for the 2015-20 RCP.)

[110] The decline in underlying SAIDI is because four days which were previously classified as MEDs would not have been classified as MEDs and consequently the interruptions that would still occur on those days that were previously excluded, would now be included in the underlying reliability.

The overall STPIS outcome, shown in Table 7.19, is the result of four days previously classified as MEDs no longer being classified as MEDs.

Table 7.19: Annual average reliability impacts from four programs of works

	Urban		Rural Short		Rural long		Dist System	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
Hardening the Network	(1.00)	0.007	(1.42)	(0.003)	(3.75)	(0.002)	(1.48)	0.004
Low reliability	0.00	0.000	2.48	0.013	2.02	0.006	0.68	0.003
Remote communities	-	-	0.53	0.002	1.51	0.003	0.32	0.001
Micro Grid	-	-	-	-	0.74	0.006	0.12	0.001
Total	**(1.00)**	**0.007**	**1.60**	**0.012**	**0.52**	**0.012**	**(0.36)**	**0.008**

7.9.4 Revised Proposal

Consistent with our Original Proposal, SA Power Networks revised forecast capital expenditure for reliability, as set out in Table 7.20, totals is $59.5 (June 2015, $ million).

Table 7.20: SA Power Networks' reliability improvement capital expenditure (June 2015, $ million)

Reliability improvement	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Maintain reliability (excl MEDs)	5.6	5.6	5.7	5.7	5.8	**28.3**
Hardening the network	2.0	3.0	3.6	4.0	4.6	**17.3**
Low reliability feeders	1.0	1.4	1.8	2.2	2.2	**8.6**
Remote communities (Hawker and Elliston)	0.5	1.2	0.7	0.0	0.0	**2.4**
Micro-grid trial	0.0	0.0	0.5	1.4	1.0	**2.9**

7.10 Augmentation: Strategic – Network Control

The AER did not accept our forecast strategic – network control capital expenditure of $25.8 (June 2015, $ million) and excluded this forecast expenditure from its substitute estimate in its Preliminary Determination.

In its Preliminary Determination the AER claims it supports innovation and new technology that allows a business to more efficiently and effectively maintain service levels[111], and yet it did not accept any of our proposed smarter network initiatives or SCADA investment.

SA Power Networks does not accept the AER's Preliminary Determination in relation to this expenditure and has included a revised forecast of $26.5 (June 2015, $ million) in this Revised Proposal. Our reasons are explained below.

7.10.1 Rule requirements

Clause 6.5.7(a) of the NER provides that SA Power Networks must submit a building block proposal that includes forecast capital expenditure it requires to meet the capital expenditure objectives for the 2015-20 RCP. This includes capital expenditure required to maintain the quality, reliability and security of SA Power Networks' SCS.

The AER **must** accept the proposed capital expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied the forecast capital expenditure for the 2015-20 RCP reasonably reflects the capital expenditure criteria. In making this assessment, the AER must have regard to the capital expenditure factors which includes the Consumer Engagement Factor.

7.10.2 SA Power Networks' Original Proposal

Supervisory Control and Data Acquisition (**SCADA**) is a key service used by SA Power Networks' Network Operations Centre (**NOC**) to manage and control the distribution network. SCADA control and monitoring of the distribution network is an industry standard across the Australian electricity industry. The SCADA system is used to gather, process, and display information about the status of the network as well as change the operating state of devices remotely. The system comprises a central Master Station and numerous field installed Remote Terminal Units (**RTUs**), Telephone Dialling Units (**TDUs**) and Data Concentrators which aid in transferring data from field based Intelligent Digital Devices (**IEDs**), such as substation relays and midline protection reclosers, back to the master station.

With SA Power Networks' evolving distribution network, there is a requirement to further develop SCADA network control and monitoring to optimise network and asset performance, provide an acceptable service level to customers and meet regulatory obligations and requirements.

SA Power Networks SCADA augmentation priorities over the 2015-20 and 2020-25 RCPs are as follows:

- completion of the upgrade of the existing Citect SCADA Master Station to the Advanced Distribution Management System (**ADMS**) as set out in Section 7.16;
- continue the rollout of supervisory control and monitoring on key network assets in the distribution system to provide adequate tools for network management and providing actual data for RIN reporting; and

[111]AER, *Preliminary Decision SA Power Networks determination 2015-16 to 2019-20,* Attachment 6 – Capital expenditure, April 2015, page 69.

- continue the rollout of SCADA to remote substations and midline assets to assist in modelling the network accurately in the ADMS and better outage restoration.

SA Power Networks proposed the programs relating to the follow assets in its Original Proposal:

- SCADA to 33 kV protection switches;
- SCADA to 11kV and 19kV reclosers; and
- SCADA to remaining substations.

SCADA to 33kV Protection Switches

In our Original Proposal, SA Power Networks proposed forecast capital expenditure of $8.2 (June 2015, $ million) to continue rolling out SCADA to 33kV protection switches.

SA Power Networks has limited supervisory control and monitoring of the 33kV sub-transmission network resulting in limitations to the adequate management of the network and utilisation of the ADMS. This program excludes forecast capital expenditure associated with SCADA to reclosers for bushfire mitigation.

SCADA to 11kV and 19kV reclosers

In our Original Proposal, SA Power Networks proposed forecast capital expenditure of $8.6 (June 2015, $ million) to continue rolling out SCADA to 11kV and 19kV reclosers in metropolitan and rural areas that are unmonitored. At present SCADA is mainly limited to the main supply points on the network, with the increasing use of mid line reclosers, the NOC has a diminishing view of the status of the network.

SCADA to remaining substations

In our Original Proposal, SA Power Networks proposed forecast capital expenditure of $9.0 (June 2015, $ million) to continue rolling out SCADA to country substations. Presently there is extensive SCADA coverage of substations within the greater metropolitan area of Adelaide. However there are many substations within regional areas of South Australia without SCADA control or monitoring.

In the absence of SCADA control and monitoring, there are lower levels of network management and control. In particular, without SCADA there is a dependency on customer service request calls to identify substation interruptions, and a reliance on line crews to travel to site in order to undertake local operations during restoration work.

Given the ageing population of our assets, installing SCADA in country substations is essential in order to maintain the current levels of reliability and customer service. Conceptually, as assets age there is a greater probability of failure and SCADA is essential to identifying these failures through remote alarm annunciation. Furthermore, the metering information from these substations is essential to ensure that there is sufficient distribution capacity to supply increases in demand in the long term.

The above programs are primarily required to manage the functionality of our network and to achieve our service levels given the ageing nature of our network. This program excludes forecast capital expenditure associated with SCADA to reclosers for bushfire mitigation as set out in Section 7.6 of this Revised Proposal.

7.10.3 AER's Preliminary Determination

In its Preliminary Determination, the AER did not accept our proposed capital expenditure forecast of \$25.8 (June 2015, \$ million) for the continuation of SCADA rollout to switches and country substations because it *'considers that it does not reasonably reflect the costs that a prudent operator, acting efficiently, would require to maintain service levels on the network.'*[112]

The AER explained that it supports innovation and new technology that allows a business to more efficiently and effectively maintain service levels, however it was of the view SA Power Networks did not provide sufficient evidence that additional network control equipment is required to maintain service levels on the network.

SCADA to 33kV, 19kV and 11kV protection switches

In its Preliminary Determination, the AER was of the view that we did not provide sufficient information to demonstrate that rolling out SCADA to our HV switches is necessary to maintain network service levels.

While the AER recognised SCADA is beneficial for metropolitan networks, major feeders and critical assets, it disputed the rollout of SCADA across the network and deemed it was not necessarily industry standard except where it can be shown there is a positive benefit to customers. In that regard, the AER was of the view that SA Power Networks did not adequately demonstrate the benefits of this program to customers.

Furthermore, the AER stated that *'Given that SA Power Networks' program is the continuation of a historical program, we consider that the most beneficial investment has likely been completed and what remains is of marginal net benefit to consumers.'*[113]

In our Original Proposal, under our Smarter Network Strategy, we considered more centralised control and automation of our feeders are necessary in the 2015-20 RCP to manage projected increases in 'two-way power flows' from solar generation. However, the AER was of the view that it did not consider that solar generation is expected to increase to the extent forecast by SA Power Networks, unless the latest AEMO National Electricity Forecasting Report (**NEFR**) in June 2015 indicates otherwise.

Based on this uncertainty, and the lack of a supporting business case, the AER was of the view that SA Power Networks had not provided sufficient evidence to justify the capital expenditure for SCADA controlled switches for the 2015–20 RCP.

SCADA to remaining substations

In its Preliminary Determination, the AER highlighted that since the 1990s SA Power Networks has progressively rolled out SCADA to larger, primarily metropolitan zone substations.

The AER has incorrectly assumed that SA Power Networks has installed SCADA in all of our high priority substations. Whilst this is somewhat correct based on 'load', there are many rural substations located within HBFRAs that would benefit from SCADA, to mitigate customers being needlessly disconnected[114] during catastrophic fire danger weather events.

---

[112] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-70.
[113] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-71.
[114] With SCADA control, disconnection can be more localised.

The AER noted SA Power Networks proposal was supported by a business case prepared by DNV-GL that considered there to be a positive benefit to customers to rollout SCADA to country substations. In its review of the DNV-GL business case the AER formed the view that there were a number of flaws or overestimations in the business case which meant the benefits to consumers, in its view, were likely to be significantly overstated for the following reasons:

- the VCR value used by the business case is higher than the VCR published by AEMO for South Australia (which is $38,090 per MWh) and so the calculated benefits using VCR must have been overstated;
- a major benefit identified is reduced zone substation visits and this benefit (being the number of predicted annual visits per substation) was overstated; and
- the benefit from managing customer generation to potentially avoid the need to undertake network augmentation for new generation, was not substantiated and generator monitoring arrangements with large connection customers could be implemented without the need to install SCADA capability.

The AER also formed the view that SA Power Networks' proposal and its business case did not explain how the costs of the program are shared between the 2015-20 and 2020-25 RCPs.

Based on the above, the AER was not satisfied that the proposed benefits outlined in the business case are accurate and that the overall cost-benefit would be positive for customers.

7.10.4 SA Power Networks' response to AER Preliminary Determination

We do not accept the AER's decision to reject our proposed network control capital expenditure forecast.

It appears that the AER has formed a general view in its Preliminary Determination that one of the main drivers for installing SCADA controlled devices is *'to adopt smart grid technology to manage two-way networks from projected increases in solar generation and other micro-generation installations'*. While SCADA is an enabler for a 'smarter network' and managing two-way networks is just one reason for implementation, it must be kept in context. SCADA is a standard industry practice in the distribution sector. The primary purpose of SCADA is to facilitate control and monitoring of existing assets, ensuring efficient asset and load management to maintain the reliability and security of the network.

Furthermore, in the Preliminary Determination, there appears to be confusion between SCADA and ADMS. To clarify:

- **ADMS** is a master station which is considered 'non-network' under the AER's Capital Expenditure Incentives Guidelines (the ADMS master station is located in the Network Operations Centre); and
- **SCADA** is the service which enables control and monitoring of the network via the ADMS master station.

The AER refers to a rollout of SCADA and ADMS to rural substations and midline devices. That is misleading.

It is incongruous for the AER to indicate, that it supports innovation and new technology that allows a business to more efficiently and effectively maintain service levels[115], but then, not accept any of our proposed smarter network initiatives or SCADA investment in its Preliminary Determination.

[115] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 6-69.

SCADA to 33kV, 19kV and 11kV protection switches

We do not accept the AER's preliminary decision to reject our proposed capital expenditure forecast for SCADA to 33kV, 19kV and 11kV protection switches because it was of the view that SA Power Networks did not provide sufficient information to demonstrate that the continuation of the roll out of SCADA to our HV switches is necessary to maintain network service levels.

SA Power Networks ageing network must be controlled and monitored effectively to maintain customer service levels. A comparably small investment in SCADA is, by far, more cost effective than having assets or power lines exceed their rating, potentially resulting in major customer supply disruptions. The benefits of SCADA lie in greater security of supply for customers and enabling the provision of actual data for planning and reporting purposes.

In its Preliminary Determination, the AER was of the view that the rollout of SCADA across the network is not necessarily industry standard except where it can be shown there is a positive benefit to customers and that we did not adequately demonstrate a benefit to customers. This view is incorrect.

There are NSPs in Australia which have more than 80% SCADA coverage while SA Power Networks' SCADA coverage is below 50%. The extent of present day SCADA coverage is a good indicator that SCADA is now industry standard. One of the benefits of substation SCADA control and monitoring is that it enables Network Control operators to be automatically notified of outages and begin the process of rectification promptly, thereby reducing the length of power outages for customers. This is explained further under *Unserved Energy Reductions that Benefit Consumers* below.

Furthermore, the AER made an assumption that, given the length of time SA Power Networks has been rolling out SCADA, there were no more benefits for customers to be had. This is an overstated and incorrect assumption by the AER. The SCADA rollout that commenced in the 1990s was purely focused on substations and was for limited SCADA capabilities (which was the then industry standard). In the 1990s SCADA consisted of a simple TDU for monitoring which then later progressed into more sophisticated RTUs for control and monitoring. The midline switches and devices which need to report to the RTUs remained old and mechanical, restricting the RTU capability. SA Power Networks only commenced installing SCADA controlled switches in the 2010-15 RCP, primarily targeting switches on bushfire risk area boundaries.

In order to enable SCADA coverage, both the SCADA assets (eg the RTU and the switching device) must be SCADA compliant. At this stage there are a significant number of switching devices in our network that are not SCADA compliant and therefore cannot communicate, provide load data reporting, or any customer benefits (eg reduced outage timeframes). This is why the continuation of our SCADA rollout program in the 2015-20 RCP is necessary.

We believe a more centralised control of our feeders is necessary in the 2015-20 RCP in order to manage projected increases in 'two-way power flows' from solar PV generation.

In its Preliminary Determination, the AER were of the view solar generation would not increase to the extent forecast by SA Power Networks, unless the latest AEMO NEFR indicated otherwise. In AEMO's most recent NEFR released June 2015, AEMO states:

> *'South Australia has the highest proportion of rooftop PV, relative to its total load, of all the NEM regions.'*[116]

[116] AEMO, *Detailed summary of 2015 electricity forecasts – 2015 National Electricity Forecasting Report*, June 2015, page 54.

Furthermore, AEMO forecasts a continued increase in residential solar PV connections and a significant increase in small commercial solar PV connections, compared to their 2014 forecasts. This further supports the need for SA Power Networks to be able to efficiently manage the impacts of 'two-way power flows' from solar PV generation.

The AER considered that we did not provide sufficient evidence to justify the capital expenditure for SCADA to our 33kV, 19kV and 11kV protection switches because there was no supporting business plan. Like our other assets, the prudent rollout of SCADA to our 33kV, 19kV and 11kV protection switches is governed by a specific Asset Management Plan (**AMP**). This AMP was submitted as Supporting Document 20.103 (SAPN Network Security and Control (AMP 2.1.02)) to our Original Proposal. All necessary information was provided to the AER in that document and we are of the view that it was not necessary to provide a further business case to the AER.

The AER noted that this program '*is continuation of an historical program to rollout network feeder automation'*. This statement is misleading because SCADA alone does not automate a network. SCADA is a platform which can be used to achieve automation as an added function. The primary function of SCADA is to provide control and monitoring; that is what SA Power Networks is aiming to achieve through the strategic network control forecast capital expenditure.

SCADA to remaining substations

We do not accept the AER's preliminary decision to reject our proposed forecast capital expenditure to roll out SCADA to our remaining country substations.

In its Preliminary Determination, the AER formed the view that the benefits in the DGA Consulting (formerly DNV-GL) business case were overstated for a number of reasons. In order to address the AER's concerns in this Revised Proposal, SA Power Networks engaged DGA Consulting (**DGA**) to undertake a review of the project benefits in consultation with subject matter experts. The findings of DGA's review are set out in a revised business case in Attachment G.10a: *Revised ADMS and ZSS Business Case*, and Attachment G.10b: *Revised ADMC and ZSS Cost Benefit Analysis*.

In its Preliminary Determination the AER noted that the value of customer reliability used in the assessment was higher than the VCR published by AEMO for South Australia, which is $38,090 per MWh. The DNV GL report provided to the AER with our Original Proposal was undertaken in mid-2014, prior to the release of the AEMO forecast. SA Power Networks agrees that the current VCR should be utilised and, in our revised business case, DGA has updated the modelling to reflect the current VCR.

The AER was also of the view that the benefit associated with zone substation visits was overstated. A material part of this benefit was the reduction in travelling time associated with rural substations. An assumption used when calculating this benefit was that, in most cases, two substation visits were required per incident. For example, if substation equipment settings had to be placed in non-automatic mode for a weather event or downstream asset works, an initial visit is required to manually apply the settings and then a subsequent visit to manually return the equipment setting to normal.

Nevertheless, DGA has reviewed this matter in consultation with SA Power Networks and, as a result, we have adopted a more conservative approach to the number of substation visits per annum, travel time and crew size, which materially reduces the overall benefit.

In addition, the AER considered that the benefit from managing customer generation to potentially avoid the need to undertake network augmentation for new generation was not substantiated and that generator monitoring arrangements with large connection customers could be implemented without the need to install SCADA capability. Our response to this is set out in Section 7.16 of this chapter.

Unserved energy reductions that benefit customers

Two of the key model calculations exhibit benefits based on Unserved Energy where benefits accrue to consumers, but there will be no impact on SA Power Networks' measured SAIDI reliability performance and therefore no impact on STPIS payments. These customer benefits are:

- **Faster capture of faults in the Outage Management System (OMS)** – One of the benefits of substation SCADA control and monitoring is that it enables Network Control operators to be automatically notified of outages and begin the process of rectification. Without SCADA, the Network operators only becomes aware of an outage after customers contact SA Power Networks and evidence of the location of the outage can be confirmed. Given SAIDI performance recording commences from the time faults are identified by the OMS, the shortened outage time will benefit the consumer but will not lead to any STPIS benefits to SA Power Networks; and
- **Reduced Off-Supply Incidents During Bushfire Conditions** – SA Power Networks has the ability to turn off power under extreme bushfire weather conditions. Time off supply for these bushfire related events is excluded from SAIDI calculations. This means that the introduction of SCADA control and monitoring may result in less customers being needlessly disconnected during extreme bushfire weather events. However there will be no impact on the SAIDI calculations, or STPIS benefits to SA Power Networks.

DGA's revised business case demonstrates strong societal benefits for this reduction of unserved energy to customers. However, the lack of benefits to SA Power Networks means that this would not be funded separately by the business.

7.10.5 Revised Proposal

SA Power Networks revised forecast capital expenditure for strategic network control is $26.5 (June 2015, $ million) for the 2015-20 RCP, as set out in Table 7.21.

In order to prioritise the proposed country substation SCADA control and monitoring rollout, SA Power Networks has undertaken a review of the 10 year program. In our Original Proposal, we proposed expansion of SCADA control and monitoring to all (203) of our remaining substations without SCADA divided evenly over the 2015-20 and 2020-25 RCPs.

The revised expenditure forecast proposes expansion of SCADA control and monitoring to 75 of our country substations in bushfire risk areas.[117] Enabling greater control and monitoring of those substations in bushfire areas which presents the highest societal benefits. Care has been taken to ensure there is no overlap with our bushfire mitigation program.

As an additional benefit, substations with SCADA will be able to provide actual data for RIN compliance. In preparing our expenditure forecast for the RIN compliance (data logger) program, we have excluded the substations that have been targeted for the SCADA roll out in the 2015-20 RCP.

For further information refer to Attachment G.10a: *Revised ADMS and ZSS business* case and Attachment G.10b: *Revised ADMC and ZSS cost benefit analysis*.

---

[117] SA Power Networks has used bushfire risk areas to prioritise SCADA installation to our country substations as there are greater benefits of having SCADA control in bushfire risk areas during extreme weather conditions. However, the primary driver of this program is to maintain customer service levels by having better control of our network, not bushfire mitigation.

Table 7.21: SA Power Networks' network control capital expenditure (June 2015, $ million)

Strategic	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Network control	5.6	7.6	6.8	4.0	2.5	26.5

7.11 Augmentation: Strategic – RIN compliance (HV monitoring)

In its Preliminary Determination, the AER did not accept our proposed capital expenditure forecast for demand driven two-way network monitoring. This program included targeted HV monitoring in our country substations without SCADA, forecast at $1.1 (June 2015, $ million) in order to comply with the 'actual' data requirements of the Economic Benchmarking (**EB**) and Category Analysis (**CA**) RINs.

SA Power Networks does not accept the AER's preliminary decision in relation to this expenditure and has included a strategic – RIN compliance (HV monitoring) forecast of $2.6 (June 2015, $ million) in this Revised Proposal. Our reasons are explained below.

7.11.1 Rule requirements

Clause 6.5.7(a) of the NER provides that SA Power Networks must submit a building block proposal that includes forecast capital expenditure it requires to meet the capital expenditure objectives for the 2015-20 RCP. This includes capital expenditure required to 'comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.'

The EB and CA RINs served on SA Power Networks by the AER are mandatory reporting requirements. The RINs require SA Power Networks to collect, store and manage certain data in the categories, and at the granular level, required by the AER. This includes the requirement to provide 'actual' data from the 2015/16 regulatory year. This is an absolute, not a 'best endeavours', obligation.

7.11.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks forecast capital expenditure of $20.5 (June 2015, $ million) to improve the visibility of our network in country areas by installing network monitoring.

As explained earlier in this chapter, network monitoring is required to enable us to proactively manage the impact of solar PV connections on our network. The main driver of this program is to proactively manage our two-way network, whilst an added benefit is to enable the collection of actual load data from our country substations without SCADA.

The $20.5 (June 2015, $ million) program was primarily LV based. However, it included $1.1 (June 2015, $ million) for HV monitoring at targeted country substations. To collect the actual substation load data, SA Power Networks proposed a combination of LV monitoring on power lines and HV monitoring within the substations.

7.11.3 AER's Preliminary Determination

In its Preliminary Determination, the AER did not accept our proposed capital expenditure forecast of $20.5 (June 2015, $ million) for demand driven two-way network monitoring. Its primary reasons were that our forecast PV connections for the 2015-20 RCP were overstated compared to AEMO's forecast, and our reactive Quality of Supply (**QoS**) approach has been effective to date in managing a significant uptake of solar PV in the 2010-15 RCP.

7.11.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks accepts the AER's preliminary decision for demand driven two-way network monitoring (with the exception of the proposed two-way network trials as discussed in Section 7.10 of this chapter). However, it is necessary for SA Power Networks to install HV monitoring in our country substations that do not have SCADA.

When forecasting the demand on the SA Power Networks network there is a new regulatory obligation to provide actual data for RIN returns. To facilitate this requires the use of real measured load data from a SCADA system or, where no SCADA is available, from installed load loggers. This load data can be gained from load loggers connected to the HV network at an appropriate point, for example a 33/11kV transformer or an 11kV voltage regulator. Other load readings can be obtained from SCADA enabled reclosers where available.

Having real measured load data will also enable us to collect the actual load data required to comply with the EB and CA RINs and undertake timely capital network augmentation expenditure. In addition, the advantages of voltage level visibility include compliance with the Australian Standard (**AS60038**) voltage levels and improved customer service from the management of two-way power flows.

There are 125 non SCADA connected sites where we propose to connect HV monitors, requiring a total of 168 load loggers.

7.11.5 Revised Proposal

SA Power Networks' revised forecast capital expenditure for RIN compliance (HV monitoring) is $2.6[118] (June 2015, $ million), as set out in Table 7.22. This forecast capital expenditure excludes the substations targeted for SCADA control and monitoring as discussed Section 7.10.

Table 7.22: SA Power Networks' RIN compliance (HV monitoring) capital expenditure (June 2015, $ million)

Strategic	2015/16	2016/17	2017/18	2018/19	2019/20	Total
RIN compliance	1.3	1.3	0.0	0.0	0.0	2.6

[118] Our Revised Proposal for HV monitoring has increased from $1.1 to $2.6 (June 2015, $ million) because more HV monitors are required to collect data for RIN reporting. Previously we proposed a combination of HV and LV monitoring.

7.12 Augmentation: Strategic – LV network monitoring

In its Preliminary Determination, the AER did not accept our proposed forecast strategic – network monitoring (two-way network) capital expenditure of $16.1 (June 2015, $ million) and excluded this forecast expenditure from its substitute estimate.

SA Power Networks does not accept the AER's Preliminary Determination in relation to this expenditure and has included a revised forecast of $3.5 (June 2015, $ million) in this Revised Proposal. Our reasons are explained below.

7.12.1 Rule requirements

Clause 6.5.7(a) of the NER provides that SA Power Networks must submit a building block proposal that includes forecast capital expenditure it requires to meet the capital expenditure objectives for the 2015-20 RCP. This includes capital expenditure required to maintain the quality, reliability and security of SA Power Networks' SCS.

The AER must accept the proposed capital expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied the forecast capital expenditure for the 2015-20 RCP reasonably reflects the capital expenditure criteria. In making this assessment, the AER must have regard to the capital expenditure factors which includes the Consumer Engagement Factor.

7.12.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks included a strategic capital expenditure forecast of $16.1 (June 2015, $ million) to establish voltage monitoring at selected customer premises in older areas of the low voltage (**LV**) network. This requirement arose as a result of Quality of Supply (**QoS**) modelling undertaken by consultant PSC. The modelling predicted that the current approach to voltage regulation would be unlikely to maintain the regulated QoS standards at customer premises once solar PV penetration in older areas of the network exceeded 25%. These issues arise because of the significant 'two-way flows' brought about by small scale generation and the fact that such issues had not been anticipated at the time when those parts of the network were designed and constructed. Parts of the LV network already significantly exceed this level of PV penetration, and the continued uptake of PV over the course of the 2015–20 RCP and beyond is forecast to cause significant further deterioration in power quality.

SA Power Networks' strategy was to install telecommunications modules in smart-ready meters at the time of meter replacement for a targeted subset of new and replacement meters located in urban areas with older LV network infrastructure. This would enable us to use these meters as voltage monitors at low incremental cost, and establish, over time, a broad-based voltage monitoring capability across those areas of the LV network most affected by voltage variations due to solar PV.

This strategy relied on another aspect of our Original Proposal, being our proposal to install more advanced meters as standard in all new and replacement situations from 2015 to support cost reflective network tariffs. It was anticipated that approximately 15% of the new and replacement meters installed per annum would be candidates to be enabled as power quality (**PQ**) monitors. The forecast installation rate was 10,000 telecommunications modules per annum over the 2015-20 RCP, which would achieve 80% coverage of target areas by 2020, with the remainder to be installed in the 2020-25 RCP.

7.12.3 AER's Preliminary Determination

In its Preliminary Determination, the AER did not accept our strategic capital expenditure forecast of $16.1 (June 2015, $ million) for LV network monitoring to manage voltage variations arising from two-way power flows in the LV network.

The AER acknowledged that our strategy to adopt new technology to manage two-way power flows in the LV network by installing targeted smart ready interval meters to enable monitoring was a response to our projected increases in solar PV generation and other micro-generation installations. However, the AER's Preliminary Determination rejected our proposed capital expenditure to install more advanced meters over the 2015–20 RCP on the basis that the AER did not consider this to be prudent '*in the context of the expected market led rollout of smart meters in South Australia, and finalisation of national smart meter minimum functionality specifications.*'[119]

As it did not approve the installation of smart-ready meters, the AER reasoned that:

> *'it is unclear whether or how many smart meters SA Power Networks will own and install in the 2015–20 regulatory control period. Irrespective of any proposed benefits from network monitoring, we consider that providing an allowance to install telecommunications modules in smart ready interval meters is not prudent without more certainty about the rollout of smart meters in South Australia'.*[120]

7.12.4 SA Power Networks' response to AER Preliminary Determination

We do not accept the AER's decision to reject our two-way network capital expenditure.

The analysis SA Power Networks has undertaken indicates that we will not be able to meet our regulatory obligation to maintain supply voltage to the Australian Standard in areas of high solar PV penetration in the 2015-20 RCP using our existing approaches that rely on customers to report voltage irregularities. Our regulatory obligation is not limited to remediating issues that customers identify, particularly when, in many instances, customers cannot readily identify that the issues exist.

Since our Original Proposal was submitted to the AER, we have obtained additional evidence that indicates the voltage issues predicted by the PSC modelling are already emerging, and moreover, the extent of these issues is significantly greater than is revealed by the number of customer complaints. This evidence is provided in Attachments G.12a and G.12b: *Voltage monitoring in the LV network*.

While PSC's modelling suggests that it will be possible to correct these voltage issues using established practices (such as replacement or re-tapping of distribution transformers, targeted augmentation, etc) in many cases, we are unable to undertake the remedial action required to meet our regulatory obligation to maintain supply voltage to required standards if we do not have the capability to detect the issues as they emerge.

While we still consider that smart meters will ultimately offer the most efficient platform for monitoring voltage across the LV network, we accept that the AER's rejection of our proposal to install more advanced meters as standard. However, this effectively prevents us from establishing a broad-based monitoring capability based on smart meters in the 2015-20 RCP.

---

[119] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-69.
[120] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-69.

In determining the most effective way to target our proposed monitoring in the short term, we have taken into account the AER's view that '*it is prudent to adopt a 'wait and see' approach … . This will allow SA Power Networks to consider the actual quantum and impact of additional solar panel installation on power quality problems, and its ability to manage these problems using existing industry standard approaches*'.

On this basis, we now propose a staged approach, in which we will deploy a smaller number of grid-side monitoring devices to targeted areas in the 2015-20 RCP. This deployment will be implemented in two phases:

- First, to an established trial area in the Unley Park area south of Adelaide that has a typical mix of suburban dwellings and typical levels of solar PV penetration. This will enable us to track 'the actual quantum and impact of additional solar PV panel installation on power quality problems' for customers in this area as solar PV penetration continues to rise through the 2015-20 RCP; and
- Secondly, to a number of specific areas where we have older LV network infrastructure and very high solar PV penetration levels (>50% penetration today). Monitoring in these areas will enable us to assess our 'ability to manage these problems using existing industry standard approaches' and facilitate meeting our regulatory obligations in the 2015-20 RCP within the allowance for voltage regulation approved by the AER.

Overall, this approach will see 424 LV monitors deployed in Phases 1 and 2 over the 2015-20 RCP.

We will defer the broader expansion of monitoring until Phase 3, which will be undertaken in the 2020-25 RCP. At this time we hope to be able to access power quality data from third-party smart meters rolled out under the new competitive metering framework, and we will have a basis of evidence from Phase 1 and Phase 2 to inform and refine our approach to Phase 3, including the specific data and services we require from third-party metering coordinators.

Under this revised approach to LV network monitoring, we are deferring the majority of the cost of broad-based monitoring to the 2020-25 RCP.

Further details on our LV network monitoring strategy are set out in Attachments G.12a and G.12b: *Voltage monitoring in the LV network*.

7.12.5 Revised Proposal

SA Power Networks revised forecast capital expenditure for strategic two-way network (network monitoring) is $3.5 (June 2015, $ million), as set out in Table 7.23.

This forecast capital expenditure has reduced from $16.1 to $3.5 (June 2015, $ million) as a result of the deferment of the majority of the cost of broad-based monitoring to the 2020-25 RCP.

Table 7.23: SA Power Networks' two-way monitoring capital expenditure (June 2015, $ million)

Strategic	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Two-way monitoring	1.5	2.0	0.0	0.0	0.0	3.5

There is also a corresponding significant reduction in our forecast non-network IT capital expenditure for back-office systems associated with LV monitoring. This has been taken into account in our revised capital forecast as set out in Section 7.15 of this Revised Proposal.

There is also an operating costs associated with this revised strategy. Refer Section 8.17 of this chapter.

7.13 Connections and Contributions

In its Preliminary Determination, the AER accepted our proposed forecast connections and contributions delivering a net connections capital expenditure of $189.4 (June 2015, $ million). However, the AER amended our Connection Policy as it did not accept our proposed customer augmentation charge rate for the upstream shared network.

SA Power Networks accepts the AER's Preliminary Determination in relation to this expenditure but has adjusted its customer contributions forecast to reflect the revised Connection Policy as summarised in Table 7.24.

Table 7.24: Connections and contributions forecast capital expenditure by key driver (June 2015, $ million)

Customer connections and contributions	Original Proposal	Preliminary Determination	Revised Proposal	Comment
Connections net	**189.4**	**189.4**	**190.8**	
Connections gross	718.0	718.0	723.1	Accept, see below
Contributions	(528.5)	(528.5)	(532.2)	Not Accept, see below

Note: Slight variations between the Original Proposal, Preliminary Determination and the Revised Proposal occur even when we accept the AER's preliminary decision, is due to the adjustment for the augmentation charge rate and to materials and labour escalation adjustments, refer to Section 7.22.

7.13.1 Rule requirements

Clause 6.5.7(a) of the NER provides that SA Power Networks must submit a building block proposal that includes forecast capital expenditure to meet the capital expenditure objectives for the 2015-20 RCP. This includes capital expenditure required to meet our regulatory obligations and requirements, and to maintain the quality, reliability and security of SA Power Networks' SCS.

In addition to the general requirements of undertaking and supporting efficient investment in, and efficient operation and use of, electricity services for the long term interests of customers with respect to the price, quality, safety, reliability and security of electricity supply, SA Power Networks must update its Connection Policy to comply with clause 6.7A.1 of the NER by adopting the Connection Charge Principles outlined in clause 5A.E.1 of the NER and ensuring consistency with the AER's Connection Charge Guidelines, in accordance with requirements under the National Energy Customer Framework (**NECF**).

The AER **must** accept the proposed capital expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied the forecast capital expenditure for the 2015-20 RCP reasonably reflects the capital expenditure criteria. This includes a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

7.13.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks forecast net customer connections expenditure of $189.4 (June 2015, $ million) based on forecast connections of $718.0 (June 2015, $ million) minus forecast contributions of $528.5 (June 2015, $ million).

SA Power Networks engaged BIS Shrapnel (**BIS**) to prepare a forecast of its customer connection expenditure from 2014/15 to 2019/20. This report was included as Attachment 12.5 to our Original Proposal. These forecasts relied on source data from the Australian Bureau of Statistics (**ABS**), in particular ABS catalogue numbers 8752.0 (Building Activity) and 8731.3 (Building Approvals), and our historical and forecast data.

For each of the four categories of connections,[121] SA Power Networks calculated the proportion of the customer contribution to the connection costs on the basis of our new Connection Policy (2015/16 to 2019/20 period). This aligns with our historical contribution and connections ratio.

SA Power Networks' forecast connection expenditure (gross and net) and contributions for the 2015-20 RCP were developed based on the full adoption of new NECF obligations (inclusive of Connection Charge Guidelines; under Chapter 5A of the NER).

7.13.3 AER's Preliminary Determination

In its Preliminary Determination, the AER accepted our forecast capital expenditure for connections and contributions. However, the AER did not accept our proposed Connections Policy because the customer augmentation charge rate for the upstream shared network was not consistent with the methodology set out in the AER's Connection Charge Guideline, as we did not consider connection asset lives.[122]

7.13.4 SA Power Networks' response to AER Preliminary Determination

We believe the AER has not considered the impact of its reduction in the augmentation charge rate on the net capital expenditure we will incur in the 2015-20 RCP.

The AER accepted that our proposed marginal cost rates for shared network augmentation were reasonable and were less than our actual historical costs and the findings of the Productivity Commission's review on long run marginal cost of network augmentation.[123]

Although the AER accepted our forecast, the reduced customer augmentation charge rate in its Preliminary Determination will reduce the customer's augmentation contribution. The effect of this would be an increase in the net connections capital expenditure we will need to incur, without the AER making an allowance for this increase in its total capital expenditure forecast. This would be inconsistent with the capital expenditure objectives.

7.13.5 Revised Proposal

Our revised forecast net customer connections expenditure is $190.8 (June 2015, $ million), as set out in Table 7.25. This forecast, takes into account adjustments we have made to reflect the revised Connection Policy.

---

[121] The four categories of connections are: minor, medium and major customer connections and underground residential developments.
[122] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 18-7.
[123] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 18-10.

Table 7.25: SA Power Networks' connections capital expenditure (June 2015, $ million)

Customer connections expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Connections	136.3	138.9	141.7	149.1	157.0	723.1
Contributions	(102.2)	(102.5)	(104.3)	(109.0)	(114.2)	(532.2)
Net expenditure	34.1	36.4	37.5	40.1	42.8	190.8

7.14 Non-network

In its Preliminary Determination, the AER did not accept our forecast of total non-network capital expenditure of $620.1 (June 2015, $ million) and included a substitute estimate amount of $337.7 (June 2015, $ million).

SA Power Networks does not accept the AER's Preliminary Determination in relation to this expenditure, as summarised in Table 7.26.

Table 7.26: Non-network forecast capital expenditure by key driver (June 2015, $ million)

Non-network	Original Proposal	Preliminary Determination	Revised Proposal	Comment
Non-network total	**615.6**	**369.5**	**513.0**	
Information Technology	353.7	213.6	299.7	*Refer Section 7.15*
Communications	**25.5**	**0**	**15.9**	
Network Operations Centre (ADMS)	*11.1*	*0*	*8.1*	*Refer Section 7.16*
Telecommunications Network Operation Centre (TNOC)	*9.0*	*0*	*5.8*	*Refer Section 7.17*
Radio network	*5.4*	*0*	*2.0*	*Section 7.18 and Section 8.20*
Vehicles	**146.0**	**103.2**	**122.9**	
Replacement	*113.8*	*103.2*	*103.2*	*Accept, see below*
New fleet	*25.6*	*0*	*16.7*	*Refer Section 7.19*
In-Vehicle Management System	*3.0*	*0*	*3.0*	*Refer Section 7.19*
Weight compliance	*3.6*	*0*	*0*	*Accept, see below*
Property	**111.6**	**71.8**	**91.7**	**Refer Section 7.20**
Other				
Plant and Tool	*26.7*	*28.8*	*28.8*	*Accept, see below*
Distribution network pricing rules	*0*	*0*	*2.6*	*Refer Section 7.21*

Non-network	Original Proposal	Preliminary Determination	Revised Proposal	Comment
Superannuation	**(47.9)**	**(47.9)**	**(48.6)**	

Note: Slight variations between the Original Proposal, Preliminary Determination and the Revised Proposal occur even when we accept the AER's preliminary decision, due to materials and labour escalation adjustments, refer to Section 7.22.

We discuss the AER's Preliminary Determination and our response in relation to non-network expenditure by key driver below and in sections 7.15 to 7.21 of this chapter.

Information Technology (IT)

The AER accepted our forecast recurrent IT capital expenditure of $126.0 (June 2015, $ million). However, in its Preliminary Determination, the AER did not accept our forecast non-recurrent IT capital expenditure. This in turn impacts on our forecast recurrent capital expenditure. SA Power Networks does not accept the AER's preliminary decision. The reasons for our revised forecast capital expenditure are explained in Section 7.15 of this chapter.

Communications

AER incorrect allocation of non-network communications

In its Preliminary Determination, the AER incorrectly allocated SA Power Networks' non-network communications expenditure as explained below.

SA Power Networks' Reset RIN data was based on our Submission Expenditure Model (**SEM**) output. SA Power Networks, in its day to day operations, does not allocate business telecommunications and communications related expenditure into a 'non-network' category, as defined in the AER's Expenditure Forecast Assessment Guideline.

On this basis our SEM did not have an available 'non-networks communications' tab. The forecast capital expenditure for business related telecommunications and communications was included in the following expenditure categories within the SEM:

- TNOC management systems expenditure (of $9.0 million) was included in the replacement, SCADA, network control and protection category;
- network switching DMS/SCADA expenditure (of $11.1 million) was included in the augmentation, strategic - network control category; and
- Government Radio Network (**GRN**) (of $5.4 million) was included in the replacement other/safety category.

As explained in the 'AER SAPN 005' response to the AER, the non-network communication projects were reported in both the Augex (Tab 2.3) and Repex (Tab 2.2) templates, and duplicated in the non-network (Tab 2.6) template, in the Reset RIN return. These amounts were then deducted in the balancing item in Table 2.1.1 (Standard Control Services Capex) of the Reset RIN.

When the AER undertook its analysis it incorrectly subtracted the balancing item from the total capital expenditure forecast (refer to the capex model *'AER - Preliminary decision SAPN distribution determination - Capex - April 2015*', cells: K26-O26; K27-O27 and K28-O28). This, in effect, removed the balancing item and reallocated the non-network communications projects back into their original expenditure categories.

In its Preliminary Determination, the AER did not accept any strategic network control expenditure and adjusted the un-modelled replacement expenditure based on historic forecasts. Accordingly, the AER excluded the forecast capital expenditure for non-network communications projects.

SA Power Networks is of the view that the AER incorrectly assessed these projects (within replacement and strategic augmentation) and did not provide reasons as to why this expenditure was not accepted.

SA Power Networks has submitted:

- a revised capital expenditure forecast for network switching DMS/SCADA (ADMS), refer Section 7.16 of this chapter;
- a revised capital expenditure forecast for TNOC, refer Section 7.17; and
- a revised operating expenditure forecast for the GRN, refer to the 'Government Radio Network' explanation below and Sections 7.18 and 8.20.

SA Power Networks has also modified the SEM to incorporate a 'non-network communications' tab to avoid further confusion.

Network Operations Centre (NOC)

In its Preliminary Decision, the AER did not accept our proposed forecast communications – Network Operations Centre (**NOC**) capital expenditure of $11.1 (June 2015, $ million). SA Power Networks disagrees with the AER's decision. The reasons for our revised forecast capital expenditure are explained in Section 7.16.

Telecommunications Network Operations Centre (TNOC)

In its Preliminary Determination, the AER did not accept our proposed forecast communications – Telecommunications Network Operations Centre (**TNOC**) capital expenditure of $9.0 (June 2015, $ million). SA Power Networks disagrees with the AER's decision. The reasons for our revised forecast capital expenditure are explained in Section 7.17.

Government Radio Network

In its Preliminary Determination, the AER did not accept our proposed forecast communications – Government Radio Network (**GRN**) capital expenditure of $5.4 (June 2015, $ million). SA Power Networks disagrees with the AER's decision. The reasons for our revised forecast capital expenditure are explained in Section 7.18.

Vehicles

Replacement

In its Preliminary Determination, the AER did not accept our proposed forecast vehicles – replacement capital expenditure. SA Power Networks accepts the AER's decision even though we consider a replacement criteria of four years for passenger and light commercial vehicles is in line with good industry practice, however we have submitted a different profile to the AER which aligns with the actual timing of our fleet replacement program, as explained in Section 7.19.

New fleet

In its Preliminary Determination, the AER did not accept our proposed forecast vehicles – new fleet capital expenditure. SA Power Networks disagrees with the AER's decision because additional fleet is required to support the delivery of the forecast network program of work. The reasons for our revised forecast capital expenditure are explained in Section 7.19.

In-Vehicle Management System

In its Preliminary Determination, the AER did not accept our proposed forecast vehicles – In-Vehicle Management System (**IVMS**) capital expenditure. SA Power Networks disagrees with the AER's decision because the IVMS are now being adopted as standard practice to ensure (so far as is reasonably practicable) workplace's are without risk to the health and safety of any person when travelling in vehicles. The reasons for our revised forecast capital expenditure are explained in Section 7.19.

Weight compliance

In its Preliminary Determination the AER did not accept our proposed forecast vehicles – weight compliance capital expenditure. Although we do not agree with the AER's assessment of this expenditure, we nevertheless accept the AER's preliminary and are not resubmitting this expenditure.

Property

In its Preliminary Determination, the AER did not accept our proposed forecast property capital expenditure. SA Power Networks disagrees with the AER's decision because it is required to support the delivery of the forecast network program of work. The reasons for our revised forecast capital expenditure are explained in Section 7.20.

Other

Plant and tool

In its Preliminary Determination, the AER accepted our forecast plant and tool capital expenditure. SA Power Networks accepts the AER's Preliminary Determination in relation to this program and has incorporated that decision into this Revised Proposal.

Distribution network pricing rules

In its Preliminary Determination, the AER did not accept our proposal to introduce cost-reflective network tariffs for small customers. SA Power Networks disagrees with the AER's decision because we now have a mandatory regulatory obligation to phase in cost-reflective pricing in the 2015-20 RCP under the new pricing principles in the NER. The reasons for our revised forecast capital expenditure are explained in Section 7.21.

Superannuation

In its Preliminary Determination, the AER accepted our superannuation capital expenditure adjustment. SA Power Networks accepts the AER's Preliminary Determination in relation to this program and has incorporated that decision into this Revised Proposal.

7.15 Non-network: Information Technology

7.15.1 Rule requirements

We have a wide range of regulatory obligations in relation to the provision of SCS. We cannot discharge those obligations without appropriate information technology (**IT**) systems and practices.

7.15.2 SA Power Networks' Original Proposal

In our Original Proposal, we included an IT capital expenditure investment program of $353.7 (June 2015 $ million).

The business requirements driving this forecast were grouped into three distinct segments:

- recurrent expenditure;
- non-recurrent expenditure; and
- business change costs.

Table 7.27: Original Proposal - IT forecast capital expenditure for 2015-20 RCP (June 2015, $ million)

IT Expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Recurrent IT expenditure	26.7	25.2	24.4	24.0	25.7	126.0
Non-recurrent IT expenditure	47.5	32.7	29.3	40.8	31.6	181.9
Business change expenditure	9.8	13.5	9.5	8.3	4.9	45.8
Total IT expenditure	83.9	71.3	63.2	73.1	62.2	353.7

SA Power Networks engaged KPMG to independently assess its methodology and approach to developing the original IT capital expenditure forecast for the 2015-20 RCP. In doing this, KPMG performed a comprehensive analysis against the NER capital objectives, criteria and factors.

KPMG's Independent Prudence and Efficient Review of the 2015-20 Regulatory Technology Submission was provided to the AER in Attachment 20.31 of the Original Proposal.

Further detail in relation to our proposed IT capital expenditure investment program was provided in Section 20.8.1 of the Original Proposal.

7.15.3 AER's Preliminary Determination

In its Preliminary Determination, the AER accepted our proposed recurrent IT capital expenditure forecast of $126.0 (June 2015, $ million). However, the AER rejected our proposed non-recurrent IT and business change capital expenditure forecasts and substituted an alternative forecast of $87.6

(June 2015, $ million) a reduction of 62% from our original capital expenditure forecast of $227.7 (June 2015, $ million).

The AER assessed our proposed non-recurrent IT capital expenditure *'…from both a top down portfolio perspective and through a bottom up evaluation of the individual business cases to assess the prudence and efficiency of the proposed capex*'.[124]

As a result of that assessment, the AER was not satisfied that our forecast capital expenditure reasonably reflected the efficient costs that a prudent operator would require to achieve the capital expenditure objectives. This view reflected the AER's conclusions that:[125]

- the proposed program is a large scale, complex and an interdependent program of works which impacts broadly across core IT systems and business processes;
- the program is to be delivered in a relatively short timeframe for such a complex portfolio of works;
- SA Power Networks' IT service management capability is, at present, relatively immature;
- SA Power Networks' proposal to substantially increase its use of outsourced resources to deliver 63 per cent of the IT capital expenditure program presents delivery risks given SA Power Networks has not previously applied this level of outsourced service delivery in the IT area;
- the risks to the successful delivery of this program in the timeframe proposed, in terms of resourcing, implementation, business process changes and the realisation of benefits, appear high; and
- in the AER's view, a prudent operator would undertake such a portfolio of work over a longer timeframe to reduce delivery and resourcing risk.

In Section 7.15.4 below we have considered each of the above conclusions and provided further evidence as to why each conclusion is incorrect in relation to our revised forecast for IT non-recurrent and business change capital expenditure during the 2015-20 RCP.

The AER noted that KPMG had provided a positive assessment of SA Power Networks' IT governance and forecasting methodology (which included a sample of the non-recurrent IT capital expenditure business cases). However, the AER also noted that KPMG had identified a few concerns in relation to the economic justification of the forecast capital expenditure, including that:

- a number of the regulatory obligations changes, such as RINs, Power of Choice and contestable metering changes, are yet to be mandated;
- the economic justifications for the planned expenditure did not comprehensively justify the investments on a NPV basis, but were supported by strong risk analysis justification; and
- whilst the IT capital expenditure per customer in 2013 was below the industry average, the forecast expenditure per customer for the 2015-20 RCP would be well above the 2013 industry mean.

Based on the information provided, the AER formed the view that our non-recurrent IT capital expenditure business cases did not provide strong economic justification for the forecast capital expenditure. The AER was of the view that the business cases typically provided few benefits relative to forecast costs, and were not economically justified.

---

[124] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 6-114.
[125] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 6-118.

In determining its alternative forecast of IT capital expenditure, the AER recognised (based on our historical low levels of IT investment and current IT asset lifecycle requirements) that an increase in expenditure was required. However, the AER did not seek to determine which of the 24 proposed non-recurrent IT capital expenditure projects SA Power Networks should pursue in the 2015-20 RCP, as it was of the view that this was a matter for SA Power Networks. Rather, the AER simply stated that it believed the allowance would cover key non-discretionary projects such as the CISOV replacement system. That is, the AER has provided no basis for how it has derived its substitute expenditure for non-recurrent IT.

We have specifically addressed this comment below as it is based on the assumption that these projects are discretionary. However, the majority of projects included in our Revised Proposal are not discretionary.

7.15.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks accepts the AER's Preliminary Determination to allow $126 (June 2015, $ million) in recurrent IT capital expenditure, but rejects the AER's reduced allowance for non-recurrent IT expenditure (including business change costs).

Necessary versus discretionary

The AER in its Preliminary Determination states that:

> *'SA Power Networks' recurrent IT capex is driven by the ongoing needs of its existing IT application and infrastructure … by its nature, [non recurrent IT capex] is more likely to relate to the introduction of new capabilities and technologies into the business, and therefore be more discretionary in nature than recurrent IT capex'.*[126]

However, SA Power Networks categorises its non-recurrent IT capital expenditure to include end of life replacements or major technical upgrades of core systems that must be undertaken to maintain the currency and security of its operating environment. In other words, SA Power Networks non-recurrent IT capital expenditure is not limited to expenditure relating to the introduction of new capabilities and technologies. Therefore, the AER's assumption that our proposed non-recurrent projects are more likely to relate to the introduction of new capabilities and be discretionary in nature is incorrect. This assumption does not reflect SA Power Networks' practices or the nature of, and the drivers for, our proposed non-recurrent IT capital expenditure. These factors cannot be ignored when considering the relevance of this general assumption to the assessment of SA Power Networks' revised non-recurrent IT capital expenditure.

Our Original Proposal included an IT capital expenditure forecast for 24 non-recurrent projects. Of those projects five were classified as 'efficiency' projects, nine were driven by compliance with regulatory obligations and requirements, and ten related to maintaining our current level of service.

The 19 projects driven by compliance with regulatory obligations and requirements and maintaining our current level of service propose to use new modern technology equivalents that are <u>not</u> discretionary in nature. These projects are required to comply with our regulatory obligations and maintain our current levels of service during the 2015-20 RCP. They are not discretionary.

When a prudent business identifies that it needs to modify its existing IT capabilities in order to comply with a regulatory obligation or requirement that business would consider all available

[126] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-114.

technologies and chose the most efficient long term solution for the required modification (ie in the context of the electricity industry, consistent with the National Electricity Objective). This is clearly an efficient and prudent approach to adopt.

Compliance with a regulatory obligation is not discretionary. The choice of the most efficient long term solution to meet that identified need may be discretionary, but only to the extent that the choice of solutions is efficient. In considering options a prudent business would not limit its review to solutions which are only able to satisfy the immediate need. In many circumstances it is clearly prudent to choose an option that satisfies the immediate need and provides the capability to efficiently address future needs (ie where it is more efficient to add additional capability as part of an existing broader project rather incrementally over time).

The AER's assumption in relation to SA Power Networks non-recurrent IT expenditure being discretionary in nature is incorrect.

Deliverability

The AER has no basis to be concerned with our ability to use outsourced resources to deliver our revised IT capital expenditure program.

Consistent with our Future Operating Model 2013-2018, in the 2014/15 regulatory year SA Power Networks delivered $53 (June 2015, $ million) in recurrent and non-recurrent IT projects. Furthermore, 74% of the labour associated with this program of works was delivered using our outsourced IT Services Panel. This demonstrates that:

- we are able to deliver a complex and increased program of IT projects, leveraging off the most suitable and competitive labour sourcing arrangements at any given time;
- our improved delivery management and governance is operating effectively; and
- our IT service management capability has improved and is not, by any means, 'immature'.

SA Power Networks is a mature and competent organisation that has successfully delivered a range of significant IT capital projects over its history. The AER has provided no information which refutes SA Power Networks' demonstrated ability to use outsourced resources to deliver significant IT projects within a short time frame or to support its view that SA Power Networks is unlikely to be able to deliver this scope of IT capital expenditure.

We also disagree with the AER's assertion that outsourcing increases the overall delivery risks of a project. If implemented correctly, outsourcing can reduce delivery risks by:

- reducing reliance on key individuals within our business;
- providing scalability and ensuring that appropriate skills are available to us as and when they are required;
- improving the accuracy of cost forecasts due to agreed negotiated rates;
- providing more effective forward planning and bundling of projects with suppliers working together to deliver projects;
- leveraging the intellectual property, knowledge of global trends and the experience of our suppliers, particularly with organisations facing similar challenges; and
- providing a shared risk exposure with our suppliers via fixed price packages and contract conditions.

Many businesses (both within and outside of the electricity industry) elect to use outsourcing to reduce delivery risk. We have successfully demonstrated the merits of this approach in 2014/15.

The IT Transformational Program described in Section 20.10.2 of our Original Proposal has delivered marked improvements in our delivery management and governance processes as well as a significant uplift in our IT Service Management (**ITSM**) maturity. Key to our success has been the significant improvements in the Corporate and IT Project Management Offices, Organisational Change Management and Enterprise Architecture. Further evidence concerning how we have been able to leverage our IT vendor arrangements and deliver our current increased IT capital expenditure work program can be found in Attachment G.13 *IT Resourcing and Deliverability* of this Revised Proposal.

Our efforts over the 2014/15 regulatory year demonstrate that our IT vendors have both the capacity and skill necessary to work in partnership with our internal teams to deliver our proposed non-recurrent IT capital expenditure program in an efficient and effective manner during the 2015-20 RCP.

In addition, SA Power Networks considers that the AER's approach of linking our ITSM maturity level in 2011 to our ability to deliver our proposed IT capital expenditure program over 2015-20 RCP is incorrect. The AER states, in its Preliminary Determination, that:

> *'In our view, this suggests that SA Power Networks' current IT service management capability is relatively immature and may struggle to deliver the proposed IT capital program in the timeframe proposed while also changing the way in which the IT function is resourced and maintaining ongoing IT operations.'*[127]

Whilst ITSM assists in maintaining IT operations and in accommodating the changes that the non-recurrent IT capital expenditure program generates, it is not in itself an assessment of the IT delivery capability of SA Power Networks. Accordingly, it should not be used to assess the maturity or capability of SA Power Networks to effectively deliver the proposed capital program of work.

We also believe that ITSM does not provide an accurate assessment of the capability of an organisation to deliver capital work. The Solisma Report specifically says *'ETSA displays a number of key strengths that are the result of the excellent work being performed in the areas of Project Management and setting business priorities'.*[128]

Despite all this, our ITSM maturity has significantly improved since 2011 when the 2011 Solisma report quoted by the AER was produced. Since that time, SA Power Networks has demonstrated improvements across many notable areas (including service strategy, design, transition and operation) and that trend of improvement is continuing. Our increased maturity in ITSM has enabled us to continue to maintain our current IT operations while delivering the increased IT work program of $53 (June 2015, $ million) in 2014/15.

Since undertaking the IT Transformational Program described in Section 20.10.2 of our Original Proposal and implementing our revised IT Operating Model in 2014, our business-as-usual IT processes have worked effectively.

---

[127] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, page 6-117.
[128] 2011 Solisma Report.

Regulatory obligations and requirements

At the time KPMG prepared its report in October 2014, it noted that a number of SA Power Networks' proposed capital expenditure investments were yet to be mandated through regulatory obligations.[129] That statement did not appropriately acknowledge that the IT capital expenditure forecast for the 2015-20 RCP was by definition a forecast of the IT capital expenditure that would be required in order to comply with all applicable regulatory obligations or requirements during that RCP.

Whilst some of the proposed projects related to regulatory obligations that were still being finalised at the time of the KPMG Report, there was no doubt at that time that new regulatory obligations would be introduced during the early stages of the 2015-20 RCP (ie while details were still to be resolved it was clear that new regulatory obligations were going to be introduced during the early stages of the 2015-20 RCP). It follows that it was clearly appropriate to include within our original forecast capital expenditure an allowance on account of these 'pending' regulatory changes.

Our revised IT capital expenditure forecast takes into account the current status of each of these new regulatory obligations and the likely impact upon our forecast capital expenditure.

KPMG also expressed the concern in its October 2014 report that the economic justifications for the planned expenditure did not comprehensively justify the investments on a NPV basis, but were supported by strong risk analysis justification. The AER was also of the view that the business cases, typically provided few benefits relative to forecast costs, and were not economically justified. In particular, the AER stated that the $62.1 (June 2015, $ million) of tangible benefits identified was low as compared to the total proposed costs of $227.8 (June 2015, $ million).

We have revised the benefits based on the new program (refer Attachment G.24 *IT Benefits*) however, we note that many of the original concerns reflect the misunderstanding that the proposed expenditure was discretionary in nature. This is incorrect. Anything which could be classed as discretionary expenditure (ie not related to complying with regulatory obligations and requirements or maintaining current levels of service) has been removed from the scope of the revised IT projects.

In addition, if a project is non-discretionary (ie it is required to comply with regulatory obligations and requirements or to maintain current levels of service during the 2015-20 RCP) this must be taken into account in any economic assessment of the forecast costs of the project. SA Power Networks must comply with its regulatory obligations and requirements and maintain current levels of service. In doing this, it must implement efficient and prudent solutions. The economic assessment should focus on whether the proposed project is a prudent solution and its delivery costs are efficient.

Network pricing and contestable metering changes

Since KPMG prepared its report in 2014, the AEMC's Distribution Network Pricing Arrangements Rule was finalised in November 2014, confirming that network prices based on new pricing objective and pricing principles (that promote cost-reflective pricing) are to start in 2017.

In addition, the AEMC published a draft Rule change on the Expanding Competition in Metering and Related Services in March 2015. This will be finalised in July 2015. This Rule change will require a transition to full competition in metering during the 2015-20 RCP. The draft Rule proposes to make retailers responsible for appointing a Metering Coordinator, who will arrange meter data provision services and meter provision services to small customers from 1 July 2017. From this date all new and replacement meters must be Type 4, interval meters. More interval meters in the NEM will facilitate

[129] KPMG, *Independent Prudence and Efficiency Review of the 2015-20 Price Rest Technology Submission*, October 2014.

more cost-reflective pricing to be introduced and require significant system changes to receive and manage larger volumes of meter data from third parties.

The AEMC's Rule change will be finalised in July 2015 and it is highly unlikely that the AEMC will deviate from its draft decision. SA Power Networks' revised capital expenditure forecast therefore includes capital expenditure required to support the Rule change.

SA Power Networks' tariff and metering approach has been re-scoped in light of the AEMC's draft decision. Further detail in relation to the implications of this Rule change on SA Power Networks and our revised approach is set out in Attachment H.8 to this Revised Proposal.

RINs

The Economic Benchmarking (**EB**) and Category Analysis (**CA**) RINs served on SA Power Networks by the AER constitute mandatory reporting requirements.

SA Power Networks has consistently advised the AER that it does not currently collect, store and manage data in the categories and at the granular level that is required in order to complete the EB and CA RINs. This includes the requirement to provide 'actual' data from the 2015/16 regulatory year. This obligation is an absolute and not a 'best endeavours' obligation.

Compliance with the requirement to provide 'actual' data is even more critical because SA Power Networks' officers are required to certify by statutory declaration that, in addition to being prepared in accordance with the RIN, all actual information provided is true and accurate.

Much of SA Power Networks' asset data has been collected, categorised and maintained based on business processes and systems that have been implemented over the life of our organisation (which is nearly 70 years). These business processes and systems have organically evolved based on business and customer requirements during that period.

In order to comply with the AER's RIN requirements, we will need to <u>*fundamentally*</u> change our existing data recording and collection structures. This will involve changes to many of our core systems and business processes.

Most of these changes are driven by the fact that from the 2015/16 regulatory year, the RINs will require SA Power Networks to provide the AER with 'actual' rather than 'estimated' data.

In its Preliminary Determination the AER did not approve any operating or capital expenditure to support these significant changes and noted *'If SA Power Networks wish to invest in systems to make RIN reporting more efficient, then this is a matter for it, and not something [AER] provide an increase in funding for.'*[130] <u>If it was as simple as changing a reporting regime, we acknowledge this process should be relatively easy and not a costly exercise. However, this is not the case.</u>

To report 'actual data' to the AER as required by the RINs, the information must be:

> *'Materially dependent on information recorded in SA Power Networks' historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation in the response to the Notice.'*[131]

---

[130] AER, *Preliminary Decision, SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-91.
[131] AER, *Economic Benchmarking RIN Notice*, November 2013; AER, Category Analysis RIN, March 2014.

SA Power Networks currently provides information in the EB and CA RIN that is mostly estimated and the limited actual data is primarily manually collected and entered into disparate systems based on SA Power Networks' internal data requirements. The data is also collected and reported at a different level and by different asset type (as compared to the required level and asset type under the RIN). Therefore, there is currently no option but to make judgments and assumptions when completing the RINs. It is not possible for SA Power Networks to comply with the requirement to report 'actual data' to the AER as required by the RINs using its current systems.

The AER acknowledged in its Expenditure Forecast Assessment Guideline that:

> *'… the more detailed information requirements will increase regulatory compliance costs somewhat and may increase the complexity of the regulatory process to some degree. However, we consider that increased compliance costs are justified given the large amounts of expenditure involved and given the relatively limited information previously available to the AER in the past.'*[132]

It is unreasonable for the AER to now say that SA Power Networks should simply be able to comply with the RINs, and provide 'actual' information without incurring any additional expenditure. The expenditure we incurred in complying with the EB and CA RINs in our 2013/14 base year reflects the fact that nearly 76% of the data that was provided was 'estimated' data. As noted above, the expenditure required to record and collect actual data as required by the RINs will be significantly more than the expenditure incurred during the 2013/14 base year. An assumption that the expenditure will be broadly the same is incorrect.

To ensure that we are able to comply with our RIN obligations, we have, in preparing this Revised Proposal:

- reviewed all of our IT initiatives; and
- for RIN dependent initiatives (including Financial Management, Business Intelligence enablement, Enterprise Information Management, Intelligent Design and HR Systems) we have only included projects and capabilities that are required to provide 'actual' data in the EB and CA RINs. The remaining scope of these initiatives has been deferred to the 2020-25 RCP.

Our Enterprise Asset Management system initiative remains the same as in our Original Proposal. This system is the backbone to the collection and reporting of asset information required in order to comply with the RINs and will deliver approximately 46% of the 'actual' data we are currently unable to provide to the AER. See Attachment G.16: *IT Enterprise Asset Management Business Case*.

Our RIN Reporting initiative also remains the same as in our Original Proposal. This initiative provides additional data (such as Vegetation Management data), centralised reporting functions and business support to ensure the changes to our reporting regime can be, and are, embedded into our business. See Attachment G.19: *IT RIN Reporting Business Case*.

Clearly, SA Power Networks considers these investments as the prudent and efficient way to meet on RIN obligations which have been reaffirmed in recent correspondence from the AER:

> *'The AER has confirmed that in respect to the provision of actual information for the Economic Benchmarking and Category Analysis RINs, SA Power Networks must provide actual information. If SA Power Networks is unable to provide actual information, it must provide the AER with its best estimates and the basis*

[132] AER, *Expenditure Forecast Assessment Guideline*, November 2013, page 56.

of preparation must include an explanation as to why it is unable to provide actual information.

In assessing compliance for these RINs the AER will consider any explanation as to why SA Power Networks are unable to provide actual information.'[133]

Comparison of IT expenditure against the industry average

KPMG noted in its October 2014 report that whilst the IT capital expenditure per customer in 2013 was below the industry average, the forecast expenditure per customer for the 2015-20 RCP would be well above the 2013 industry mean. This is correct. SA Power Networks IT capital expenditure per customer in 2013 was below the industry average because SA Power Networks' made prudent management decisions to defer necessary IT capital expenditure in the 2010-15 RCP.

However, as discussed in our Original Proposal, this IT capital expenditure cannot be deferred any longer and will need to be incurred in the 2015-20 RCP along with other IT capital expenditure that is now needed to implement other aspects of SA Power Networks' IT program of work.

Our revised non-recurrent IT program

SA Power Networks acknowledges that the magnitude of the IT program of work included in our Original Proposal is a significant increase from that performed in the 2010-15 RCP. However, we reject the suggestion that SA Power Networks, as a prudent operator, would be unable to deliver the proposed program of work in the 2015-20 RCP.

Notwithstanding this, to address the AER's concerns, we have prioritised our proposed IT capital expenditure program of works by deferring lower priority initiatives to later in the 2015-20 RCP or to the 2020-25 RCP (where appropriate), effectively extending the program over ten years instead of five.

SA Power Networks firmly believes that the program included in our Original Proposal is necessary. However, in this Revised Proposal we have restructured the program based on the criticality of each initiative to our business. As a result, the non-recurrent IT capital program to be delivered in the 2015-20 RCP has been reduced by 26% in expenditure terms (from our Original Proposal).

The revised IT initiatives included in the 2015-20 RCP have been prioritised based on the following criteria:

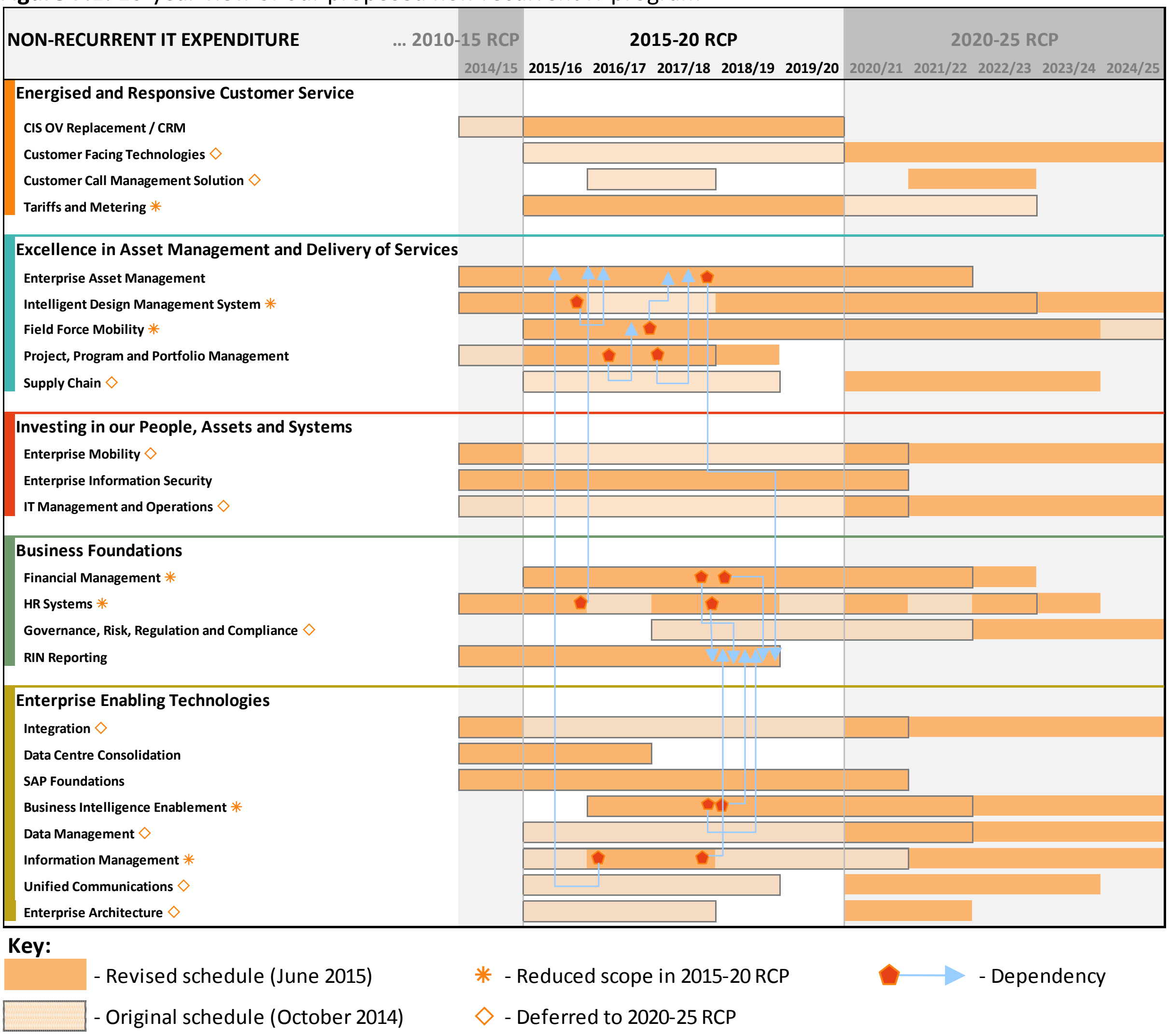
- the need to mitigate risk (such as the Data Centre Consolidation, SAP Foundations, CIS OV/CRM, Tariffs and Metering, and Enterprise Information Security initiatives);
- the requirement to meet regulatory obligations and requirements (such as the Tariff and Metering and RIN Reporting and associated initiatives); and
- the ability to leverage opportunities utilising the above initiatives to deliver the highest priority organisational strategic objectives (such as Field Force Mobility).

After this prioritisation process was undertaken, we revised our initiatives to align with our revised business strategies to deliver outcomes to meet our regulatory obligations and requirements (see, for example, Attachment G.19: *RIN Reporting*). This has resulted in a considerable number of our initiatives being reduced in scope for the 2015-20 RCP. Figure 7.1 demonstrates the impact of our prioritisation process and scope reduction on our entire IT program and identifies the initiatives deferred to the 2020-25 RCP.

---

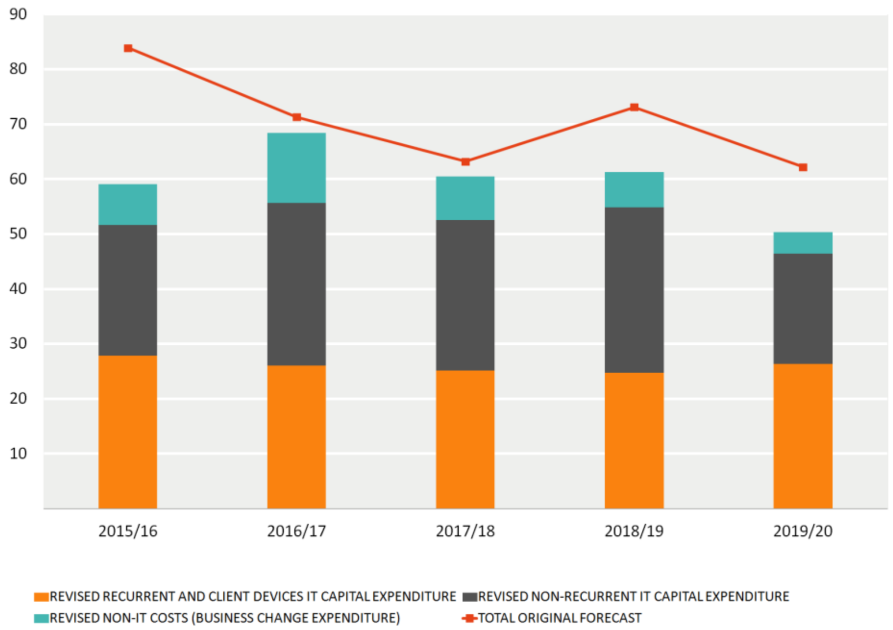
[133] Letter from AER's General Manager, Network Investment and Pricing, 20 May 2015.

Figure 7.1: 10-year view of our proposed non-recurrent IT program



The timing of our proposed initiatives has also been adjusted to provide a more uniform distribution of capital expenditure over the 2015-20 RCP and 2020-25 RCP. This can be seen in Figure 7.2, which shows the profile of the total non-recurrent IT expenditure for the 2015-20 RCP.

Figure 7.2: Comparison between the revised and the original IT capex forecasts



Our revised program of non-recurrent work has been prioritised, reduced in scope for the 2015-20 RCP and adjusted for dependencies to enable us to continue to meet our regulatory and customer obligations in a prudent, efficient and timely manner.

To demonstrate the outcomes of this process of prioritisation, we have developed Table 7.28, which identifies the non-recurrent initiatives that form the basis of our capital expenditure forecast, and provide details of our risk assessments. The initiatives are categorised according to the prioritisation criteria.

As detailed in Table 7.28, some of the non-recurrent initiatives included in our revised program involve capex/opex trade-offs. This means that should capital funding not be provided for these initiatives, SA Power Networks will require an associated increase in operating expenditure funding. Without an allowance being provided for at least this expenditure, SA Power Networks will not be able to maintain its current levels of service. Importantly, notwithstanding the capex/opex trade-offs, without the requested capital funding SA Power Networks will be unable to comply with all of its regulatory obligations and adequately manage key risks.

Table 7.28: Summary of revised non-recurrent IT initiatives for the 2015-20 RCP (June 2015, $ million)

IT initiative[134]	Risk of not doing[135]	Impact of not having capital funding	Revised capex	Opex required if Capex is disallowed
Risk mitigation to maintain our business operations (50%)				
Enterprise Information Security	Extreme	Not investing capital funding is not an option due to risk assessment.	6.7	Not viable
SAP Foundations	Extreme	Not investing capital funding is not an option due to risk assessment.	9.4	Not viable
Data Centre Consolidation	Extreme	Not investing capital funding is not an option due to risk assessment.	1.5	Not viable
CIS OV/CRM	High	Not investing capital funding is not an option due to risk assessment.	67.7	Not viable
Regulatory compliance (34%)				
Tariffs and Metering*	High	Not investing capital funding is not an option due to risk assessment.	11.1	Not viable
RIN Reporting	High	Manual data collection would need to occur throughout the business to be compliant.	14.8	23.1
Enterprise Asset Management	High	No single source of truth for asset information.	31.0	Included in RIN reporting costs

[134] The IT initiatives correspond to business cases submitted as attachments to this Revised Proposal. They consist of one or more individual projects.

[135] Extreme risks have high to almost certain likelihood of the following consequences:

- Financial – almost certain likelihood of impact of $10m or more, but less than $100m or high likelihood of $100m or more or
- WHS - Death or Permanent Disability or Multiple Fatalities or
- Environment - Long term environmental harm or Permanent irreparable damage or
- Reputation /Customer Service / Legislative and Regulatory - Loss of Distribution Licence or
- Organisational - Critical event which can be endured with targeted input OR Disaster which can cause collapse of the business or
- Reliability - Over 40,000 customers or Adelaide CBD without supply for longer than 24 hours.

As per our corporate risk management process Extreme risks can only be allowed to continue under extraordinary circumstances. Further details on specific risks are provided within individual business cases.

IT initiative[134]	Risk of not doing[135]	Impact of not having capital funding	Revised capex	Opex required if Capex is disallowed
Dependent projects driven by business strategy* (8%)				
Field Force Mobility***	High	RIN reporting initiative is not implemented Unable to realise business benefits.	8.0	6.3
Project Portfolio Management**	High	Field Force Mobility is not implemented Unable to realise business benefits.	6.3	3.9
Dependent projects required to enable regulatory compliance (8%)				
Financial Management*	High	RIN reporting initiative is not implemented resulting in manual data collection that would need to occur throughout the business to be compliant.	5.1	Included in RIN reporting costs
Business Intelligence Enablement*	High	RIN reporting initiative is not able to be implemented resulting in manual data collection that would need to occur throughout the business to be compliant.	1.5	Included in RIN reporting costs
Enterprise Information Management*	Medium	RIN reporting initiative is not implemented resulting in manual data collection that would need to occur throughout the business to be compliant.	2.5	Included in RIN reporting costs
Intelligent Design Management System*	Medium	RIN reporting initiative is not implemented resulting in manual data collection that would need to occur throughout the business to be compliant.	2.1	Included in RIN reporting costs
HR Systems*	Medium	RIN reporting initiative is not able to be implemented resulting in manual data collection that would need to occur throughout the business to be compliant. Specifically, manual data from managers throughout the business to track roles and movements of resources. Unable to generate HR system data. Calculation of costs would still be estimated. 'Actual' data unable to be collected.	1.5	Included in RIN reporting costs

* Initiatives with scope reduced.

** Business strategy driven initiatives deliver on the highest priority organisational strategic objectives and also include projects that are required to enable regulatory compliance.

Benefits and capabilities

Risk mitigation and maintaining continuity of business operations:

- adequate protection against increased levels of cyber security threats to our network to ensure our corporate and operational systems and data are protected in an event of an attack. For further information refer to Attachment G.18 *Enterprise Information Security Foundation*;
- a stable, secure and supported technology environment for our core enterprise system, SAP, that serves as a backbone for all SA Power Networks business systems. For further information refer to Attachment G.20 *SAP Foundations*;
- a modern industry standard data centre to ensure reliability and continuous operations of our business critical systems and adequate disaster recovery capability. For further information refer to Attachment G.17 *Data Centre Consolidation*; and
- a new Customer Relationship Management (**CRM**) system replacing end of life CIS OV billing and customer related applications that would have run out of support by 2021. This will allow SA Power Networks to avoid significant risks of failure associated with legacy CIS OV system and at the same time ensure that we continue to meet our compliance obligations listed below. For further information refer to Attachment G.21 *CIS CRM Business Case*.

Regulatory compliance:

- compliance with a number of AEMC rule changes including
  - '*Expanding Competition in Metering and Related Services*' Rule change (ERC0169). For further information refer to Attachment H.8 *Competition in Metering*;
  - '*Customer access to information about their energy consumption*' Rule change (ERC0171). For further information refer to Attachment G.21 *CIS CRM Business Case;* and
  - '*Distribution Network Pricing Arrangements*' (ERC0161) Rule change. For further information refer to Attachment G.21 *CIS CRM Business Case*;
- meeting our mandatory RIN reporting obligations and delivering regulatory reporting capabilities which comply with these obligations. For further information refer to Attachment G.22 *EAM and RIN Reporting*; and
- an integrated solution for RIN reporting comprising the integration of actual data from disparate sources (including personnel costs, a General Ledger aligned to assets and asset drawings aligned to assets), centralised information storage, reporting and analytics capabilities. For further information refer to Attachments G.15-G.23 (*HR Systems, Financial Management, Field Force Mobility, Portfolio Project Management, Intelligent Design Management System, Enterprise Information Management, Business Intelligence Enablement*).

Support for business strategy:

- improved asset management information collecton and decision making to ensure long-term sustainable performance and condition of assets. For further information refer to Attachment G.22 *EAM and RIN Reporting*; and
- new technology capabilities for our workforce to efficiently collect and manage the additional data, manage an increased workload and ensure we continue to meet expectations from customers for a safe, responsive service and transparent communication. For further information refer to Attachment G.15 and G.23 *Field Force Mobility and Portfolio Project Management*.

Benefits to customers:

- ensure SA Power Networks' customer services continues to meet our regulatory and market obligations;
- ensure the provision of energy services continues to meet SA Power Networks obligations;
- provide additional information to enable informed decision-making via our increased information collection capability;
- provide the capability to manage and control energy costs with improved visibility of energy consumption data; and
- ensure customer information is held and managed securely.

KPMG review of our Revised Proposal

KPMG has performed an independent assessment of our revised IT expenditure proposal, focussing specifically on SA Power Networks' responses to the AER's comments on the Original Proposal. KPMG has assessed the arguments and additional supporting evidence put forward by SA Power Networks in relation to:

- deliverability; and
- the scale of the overall IT Capex program.

The KPMG report is provided in Attachment G.13 (*Independent assessment of the revised 2015-20 Regulatory Technology Submission*).

In relation to deliverability, KPMG concluded that:

> *'Overall we have found the arguments put forward by SA Power Networks as to their capability to deliver the revised IT capital program to be well supported. Improved and improving maturity in a number of areas impacting capital delivery together with the prudent re-structuring of the total program over an increased time period should facilitate its successful completion as planned. Actual delivery of the current year's (2014/15) capital program which is similar in size and resource mix to the annual program being proposed, adds weight to SA Power Networks' position that it has the capacity and capability to deliver the program of IT capital works over the next five year period.'*

In relation to the IT Capex program, KPMG concluded that:

- the total program of work has been reduced to an annual scale comparable to the 2014/15 forecast delivery of IT capital projects;
- the proposed program has been reduced through a prudent, business lead process of prioritisation and re-assessment of efficient costs;
- the overall program has been spread over two regulatory periods thereby doubling the time period over which the IT capex program is to be delivered;
- increased maturity in change management across the business has reduced the risk of unsuccessful delivery due to a lack of acceptance by the business; and
- key dependencies have been identified to ensure that only those projects absolutely required for the highest priority outcomes are undertaken.

Summary

SA Power Networks can deliver the revised IT program of work during the 2015-20 RCP given that:

- we have a successful track record of delivering IT capital programs of a similar size;
- we have effective and efficient outsourcing and partnering arrangements in place;
- we have strong internal sourcing, vendor management, program management and enterprise investment governance capabilities; and
- our Revised Proposal minimises the business change impacts.

The forecast capital expenditure for our revised IT program reasonably reflects the efficient costs that a prudent operator would require to achieve the capital expenditure objectives.

In particular, the program of work covered by the revised forecast is not a discretionary program of work. It is required to comply with our regulatory obligations and maintain our current levels of service during the 2015-20 RCP. It is a program that is based on detailed risk assessments and follows our corporate risk treatment guidelines.

As such, the program ensures SA Power Networks can meet its regulatory obligations and requirements whilst prioritising individual high or extreme risk initiatives having had a stringent business-led prioritisation process based on strategic, regulatory and economic drivers.

7.15.5 Revised Proposal

Our Revised Proposal includes forecasts for IT capital expenditure of $299.7 (June 2015, $ million), as set out in Table 7.29.

The Revised Proposal takes into account the fact that the individual non-recurrent IT initiatives have been prioritised and, where appropriate, deferred to later in the 2015-20 RCP or to the 2020-25 RCP.

It should be noted that the recurrent expenditure has been adjusted upwards by $4.2 (June 2015, $ million) to reflect the additional costs related to minor upgrades required for projects deferred to 2020-25 RCP.

While the vast majority of this portfolio is non-discretionary and must be undertaken to enable risk management and compliance, the business strategic initiatives (Field Force Mobility and Portfolio Project Management) deliver efficiency benefits in the form of improved data collection and handling capabilities. These benefits have been offset in the Revised Proposal (as they were in the Original Proposal) by reducing the resource forecasts for the field force mobility.

Table 7.29: SA Power Networks Revised IT forecast capital expenditure for the 2015-20 RCP (June 2015, $ million)

IT Expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Recurrent IT expenditure	27.9	26.1	25.1	24.7	26.4	130.2
Non-recurrent IT expenditure	23.7	29.6	27.4	30.2	20.0	131.0
Business change expenditure	7.3	12.7	8.0	6.4	3.9	38.3
Total IT expenditure	59.1	68.4	60.5	61.3	50.3	299.7

The forecast non-recurrent IT capital expenditure and business change capital expenditure associated with each individual non-recurrent IT initiative is set out in Table 7.30.

Table 7.30: SA Power Networks revised non-recurrent IT initiatives (June 2015, $ million)

Business Case name	IT Capex	Non-IT Capex (Business Change)	Total
Enterprise Information Security	6.7	-	6.7
Data Centre Consolidation	1.5	-	1.5
SAP Foundations	9.4	-	9.4
CIS OV/CRM*	63.6	4.2	67.7
Tariffs & Metering	9.5	1.5	11.1
RIN Reporting	4.0	10.8	14.8
Enterprise Asset Management	14.0	17.0	31.0
Field Force Mobility	6.5	1.5	8.0
Project Portfolio Management*	5.4	0.9	6.3
Financial Management	3.3	1.8	5.1

Business Case name	IT Capex	Non-IT Capex (Business Change)	Total
Intelligent Design Management System	1.9	0.2	2.1
Business Intelligence Enablement	1.5	-	1.5
Enterprise Information Management	2.5	-	2.5
HR Systems	1.1	0.5	1.5
TOTAL	131.0	38.3	169.3

* Projects with slight cost adjustment in 2015-20 RCP due to the re-alignment of the program of work

7.16 Non-network: Communications – Network Operations Centre

The AER did not accept our forecast communications – NOC capital expenditure of $11.1 (June 2015, $ million) and omitted the forecast expenditure in its Preliminary Determination.

SA Power Networks does not accept the AER's decision in relation to this expenditure and has included a revised forecast capital expenditure of $8.1 (June 2015, $ million) in this Revised Proposal. Our reasons are explained below.

7.16.1 Rule requirements

Clause 6.5.7(a) of the NER provides that SA Power Networks must submit a building block proposal that includes a forecast of the capital expenditure it requires to meet the capital expenditure objectives for the 2015-20 RCP. This includes capital expenditure required to maintain the quality, reliability and security of SA Power Networks SCS.

The AER must accept the capital expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied that our forecast capital expenditure for the 2015-20 RCP reasonably reflects the capital expenditure criteria. In making this assessment the AER must have regard to the capital expenditure factors.

7.16.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks proposed forecast capital expenditure of $11.1 (June 2015, $ million) for the following Network Operations Centre (**NOC**) ADMS projects:

- Volt/VAr optimisation;
- distribution feeder management; and
- embedded generator control.

The Volt/VAr optimisation and distribution feeder management programs supported the proposed strategic network monitoring program to establish voltage monitoring at selected customer premises in older areas of the LV network. This strategy also relied on another aspect of our Original Proposal, being our proposal to install more advanced meters as standard in all new and replacement situations from 2015 to support cost reflective network tariffs.

The embedded generator control project was associated with the proposed rolling out of SCADA to country substations for control and monitoring of the network. A benefit of having SCADA control at substations is that, when combined with the ADMS functionality, it enables control of customers embedded generators. Having remote and automatic control of embedded generators enables proponents (in most cases) to connect to the network at lower cost due to lower augmentation charges. That is, provided the proponent allows SA Power Networks to control when the embedded generators are operating, for example, at times of network capacity constraints, SA Power Networks could remotely and automatically turn off the generator using ADMS (via SCADA).

7.16.3 AER's Preliminary Determination

In its Preliminary Determination, the AER stated:

> *'SA Power Networks proposes $24.7 million capex ($2014–15) [excluding overheads] over the 2015–20 period to install network control and automation equipment (SCADA) and ADMS (Advanced Distribution Management System) to its rural substations and switches. As noted previously, this is part of SA Power*

> *Networks' broader strategy to adopt smart-grid technology to manage two-way networks from the projected increases in solar generation and other micro-generation installations.'*[136]

This statement is only partially correct. The $24.7 million of proposed expenditure (or $25.5 million including overheads) was for the strategic network control component (eg the rollout of SCADA control and monitoring to HV switches and country substations). It did not include any expenditure for ADMS as this capability was implemented in the 2010-15 RCP.

SA Power Networks included an additional amount of $11.1 (June 2015, $ million) under non-network communications called Network Operations Centre. This forecast expenditure was for the three ADMS projects set out above.

Incorrect allocation of non-network communications

As explained earlier, the AER incorrectly allocated non-network communications expenditure in its Preliminary Determination. The non-network communication projects were reported in both Augex (Tab 2.3) and Repex (Tab 2.2) templates of the Reset RIN, and duplicated in the non-network (Tab 2.6) template of that RIN. An amount was deducted in the balancing item in Table 2.1.1 (Standard Control Services Capex) of the Reset RIN templates to avoid double counting.

When the AER undertook its analysis it incorrectly subtracted the balancing item from the total capital expenditure forecast (refer to the capex model *'AER - Preliminary decision SAPN distribution determination - Capex - April 2015', cells: K27-O27*). This, in effect, removed the balancing item and reallocated the Network Operations Centre expenditure back into strategic network control. However, the AER did not specifically assess this expenditure.

In its Preliminary Determination the AER stated:

> *'The benefit from managing customer generation is that it could avoid the need to augment the network for new generation. This is based on an assumption that SA Power Networks will connect large generators in the absence of additional control. We consider that the assumption that SA Power Networks can avoid such large generation in the absence of network control has not been substantiated.'*[137]

Furthermore, the AER were of the view that:

> *'SA Power Networks can implement generator monitoring arrangements with its large connection customers without the need to install SCADA capability.'*[138]

The AER was not satisfied that the proposed benefits (for the continuation of our SCADA rollout and additional embedded generator control capability) outlined in the DNV-GL business case were accurate and therefore they could not determine if there was an overall positive cost-benefit for customers. On this basis the AER did not included expenditure for SCADA control and monitoring in its substitute forecast.

7.16.4 SA Power Networks' response to AER Preliminary Determination

The AER did not correctly assess our proposed network operating centre capital expenditure forecast.

---

[136] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-68, 6-69.
[137] Ibid.
[138] Ibid.

It appears the AER has largely misunderstood the purpose of the SCADA rollout to country substations and the ADMS embedded generator control programs. As mentioned above, the AER stated:

> *'The benefit from managing customer generation is that it could avoid the need to augment the network for new generation.'*[139]

However, the correct phrasing of this statement is as follows:

> *'The benefit from managing new customer generator connections is that it could avoid the need to augment the network to facilitate the connection of those new generators.'*

By having SCADA monitoring combined with ADMS control of the embedded generator, SA Power Networks will have the ability to manage the generator connection as an alternative to augmenting the network, eg during network constraints the ADMS will disconnect the generator. Over the last five years alone, SA Power Networks connected four large generators requiring network augmentation which could have been reduced if the appropriate ADMS functionality had existed at that time.

Furthermore, it appears that the AER has not understood the difference between SCADA and ADMS. As explained in Section 7.10 of this chapter, and reiterated here for clarity, the ADMS is a master station which is considered 'non-network' under the AER's Expenditure Forecast Assessment Guideline. The ADMS master station is located in the Network Operations Centre; while SCADA is the service which enables control and monitoring of the network via the ADMS master station.

Further information in relation to the benefits of ADMS functionality is set out in Attachments G.10a and G.10b (*Revised ADMS and ZSS*).

7.16.5 Revised Proposal

SA Power Networks revised forecast capital expenditure for the NOC is $8.1 (June 2015, $ million).

Our Revised Proposal is for the implementation of ADMS embedded generation control to enable remote and automatic control of proponents' embedded generators, to reduce connection related network augmentation only. This capability is in addition to the ADMS functionality to enable day to day network control and monitoring (via SCADA) that was implemented in the 2010-15 RCP. For further information refer to Attachments G.10a and G.10b of this Revised Proposal.

We no longer propose to proceed with the Volt/VAr optimisation and distribution feeder management programs as these projects required additional equipment to be deployed on the network for network monitoring via smart meters, which the AER does not support.

SA Power Networks' NOC forecast expenditure for the 2015-20 RCP is summarised in Table 7.31.

Table 7.31: SA Power Networks' NOC capital expenditure (June 2015, $ million)

Communications	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Network Operations Centre	6.1	1.2	0.8	0.0	0.0	8.1

7.17 Non-network: Communications – Telecommunications Network Operations Centre

In its Preliminary Determination, the AER did not accept our forecast of communications – Telecommunications Network Operations Centre (**TNOC**) capital expenditure of $9.0 (June 2015, $ million) and omitted our forecast expenditure in its Preliminary Determination.

SA Power Networks does not accept the AER's decision in relation to this expenditure and has included a revised forecast capital expenditure of $5.8 (June 2015, $ million) in this Revised Proposal. Our reasons are explained below.

7.17.1 Rule requirements

Clause 6.5.7(a) of the NER provides that SA Power Networks must submit a building block proposal including a forecast of capital expenditure it requires to meet the capital expenditure objectives for the 2015-20 RCP. This includes capital expenditure required to maintain the quality, reliability and security of SA Power Networks' SCS.

The AER **must** accept the capital expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied the forecast capital expenditure for the 2015-20 RCP reasonably reflects the capital expenditure criteria. In making this assessment, the AER must have regard to the capital expenditure factors.

7.17.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks proposed forecast capital expenditure of $11.1 (June 2015, $ million) to invest in our TNOC. This investment would provide SA Power Networks with a single ubiquitous operational telecommunications management platform that in turn offers a significantly more secure and reliable end-to-end communications network for the delivery of services that are critical in the management of our distribution system.

SA Power Networks currently relies on its legacy Network Management Systems (**NMS**) to control the telecommunications network. These NMS are inefficient in managing the day-to-day operations of the telecommunications network as the existing systems operate independently of each other, requiring significant levels of manual intervention. SA Power Networks' reliance on its telecommunications network has grown significantly over the last five years and as a result reliance on our NMS alone is no longer sustainable without employing additional resources.

The NMS is a collection of software and hardware applications that support back-office applications that are used for monitoring, control and operation of the telecommunications network to maintain customer services. The NMS consists of software and hardware and is used as a platform to provide integration between systems and business processes. As a collection of integrated applications, the NMS supports the planning, design, build and running of both the communications network as a whole and the individual services that make use of that network. The NMS encompasses many highly technical network management processes but ultimately its purpose is to ensure the telecommunications network is efficient and services are meeting their service level regulatory obligations.

Given the increasing network security risks and a far greater reliance on the telecommunications network to manage and control SA Power Networks' operations and assets, it is imperative that we have a secure streamlined and integrated NMS platform.

7.17.3 AER's Preliminary Determination

In its Preliminary Determination, it appears that the AER did not specifically assess the proposed TNOC capital expenditure.

As explained in ***incorrect allocation of non-network communications*** above, the non-network communication projects were reported in both the Augex (Tab 2.3) and Repex (Tab 2.2) tabs in the Reset RIN template, and duplicated in the non-network (Tab 2.6) tabs. An amount was deducted in the balancing item in Table 2.1.1 (Standard Control Services Capex) of the Reset RIN template to avoid double counting.

When the AER undertook its analysis it incorrectly subtracted the balancing item from the total capital expenditure forecast (refer to the capex model '*AER - Preliminary decision SAPN distribution determination - Capex - April 2015*', cells: K26-O26). This, in effect, removed the balancing item and reallocated the TNOC expenditure back into replacement. However, the AER did not specifically assess this expenditure.

In addition to the TNOC capital expenditure, in our Original Proposal SA Power Networks included an operating expenditure step change of $3.5 (June 2015, $ million) to manage the increased telecommunications operations. The AER did not accept this step change.

7.17.4 SA Power Networks' response to AER Preliminary Determination

The AER did not specifically assess our proposed TNOC capital expenditure forecasts in the Preliminary Determination.

SA Power Networks is of the view that the AER incorrectly assessed these projects (within the replacement expenditure category) and did not provide a reason as to why this expenditure was not accepted.

We have taken into consideration the interrelationship between capital and operating expenditure. Given the AER has not accepted our proposed operating step change for TNOC resourcing and we have accepted that decision, it is essential that SA Power Networks is funded to invest in more efficient TNOC management systems.

7.17.5 Revised Proposal

SA Power Networks' revised forecast capital expenditure for TNOC is $5.8 (June 2015, $ million) to invest in management systems for the TNOC to maintain the reliability and security of SA Power Networks' distribution system, as set out in Table 7.32. This capex investment is essential as the operating expenditure step change proposal has not been accepted by the AER.

For further information refer to Attachment G.25: *TNOC Business Case*.

Table 7.32: SA Power Networks' revised forecast TNOC capital expenditure for the 2015-20 RCP (June 2015, $ million)

Communications	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Telecommunications Network Operations Centre	0.4	1.5	2.1	1.2	0.6	5.8

7.18 Non-network: Communications – Radio Network

The AER did not accept our forecast of communications – Radio Network (**GRN**) capital expenditure of $5.4 (June 2015, $ million) and omitted our forecast expenditure from its Preliminary Determination.

SA Power Networks does not accept the AER's decision in relation to this expenditure and has included a revised forecast capital expenditure of $2.0 (June 2015, $ million) in this Revised Proposal. Our reasons are explained below.

7.18.1 Rule requirements

Clause 6.5.7(a) of the NER provides that SA Power Networks must submit a building block proposal including a forecast of the capital expenditure it requires to meet the capital expenditure objectives for the 2015-20 RCP. This includes capital expenditure required to maintain the quality, reliability and security of SA Power Networks' SCS.

The AER **must** accept the capital expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied the forecast capital expenditure for the 2015-20 RCP reasonably reflects the capital expenditure criteria. In making this assessment, the AER must have regard to the capital expenditure factors.

7.18.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks forecast a capital expenditure of $5.4 (June 2015, $ million) to migrate our telecommunications to the South Australian GRN. The capital expenditure forecast included an amount for telecommunications infrastructure to upgrade terminals and consoles with compliant devices, and a one off telecommunications augmentation payment to the South Australian Government.

SA Power Networks owns and operates a State wide Very High Frequency (**VHF**) mobile radio communications network for the provision of voice services between the NOC and field personnel. The VHF communications network is essential to providing a safe and reliable means of communication for our field personnel during day to day operations and in emergency events. As an essential service provider, we can not rely on public telecommunications facilities, eg mobile telephone, during emergency events as the services are not guaranteed to be available.

The VHF radio licences that SA Power Networks uses to operate the mobile radio network pre-date the Australian Communications and Media Authority's (**ACMA**) bandwidth plan and this use is no longer compliant. To upgrade our telecommunications infrastructure to achieve compliance is prohibitively expensive.

Because our licences are no longer compliant, SA Power Networks is classified as a secondary user. Under ACMA's criteria, as a secondary user the ACMA has the ability to cancel SA Power Networks licences should another (compliant) user wish to operate within our frequencies.

Given SA Power Networks relies extensively on our mobile radio network, including during emergency events, the current arrangement with the ACMA present an unacceptable risk to SA Power Networks' operations.

In addition to the forecast capital expenditure, there is a corresponding step increase in operating expenditure for the GRN annual charges for network access. This expenditure was addressed in Chapter 21 of our Original Proposal.

7.18.3 AER's Preliminary Determination

In its Preliminary Determination, the AER accepted our forecast operating expenditure step change to migrate to the GRN subject to SA Power Networks completing the final business case, refer to Section 8.20 of this Revised Proposal for further information.

However, as far as SA Power Networks' can identify, the AER did not specifically assess the corresponding non-network communications capital expenditure for migrating to the GRN.

As explained in ***incorrect allocation of non-network communications*** above, the non-network communication projects were reported in both Augex (Tab 2.3) and Repex (Tab 2.2) tabs in the Reset RIN templates, and duplicated in the non-network (Tab 2.6) tab. An amount was deducted in the balancing item in Table 2.1.1 Standard Control Services Capex to avoid double counting.

When the AER undertook its analysis it incorrectly subtracted the balancing item from the total capital expenditure forecast. Refer to the capex model 'AER - Preliminary decision SAPN distribution determination - Capex - April 2015', cells: K28-O28. This in effect, removed the balancing item and reallocated the GRN expenditure back into safety. Because the GRN forecast capital expenditure was not identified in the safety expenditure category, the AER did not specifically assess this expenditure.

7.18.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks is of the view that the AER did not specifically assess the forecast GRN capital expenditure and that given the AER accepted the operating expenditure step change in its Preliminary Determination, it should have also accepted the corresponding capital expenditure necessary to enable the migration to GRN occur.

As demonstrated in our Original Proposal, transitioning our mobile radio communications to the South Australian GRN is the most prudent option to ensure the safety of our field personnel and the South Australian community.

7.18.5 Revised Proposal

SA Power Networks revised forecast capital expenditure is $2.0 (June 2015, $ million) for telecommunications infrastructure to upgrade terminals and consoles with compliant devices, as required to enable migration to the GRN.

We note that in our Original Proposal the telecommunications payment was incorrectly categorised as capital whereas it should have been categorised as an operating expenditure step change. SA Power Networks has corrected this in this Revised Proposal. Refer to Section 8.20 of this Revised Proposal for further information.

For further information refer to Attachment H.9: *Government Radio Network Business Case*.

SA Power Networks' revised GRN forecast capital expenditure for the 2015-20 RCP is summarised in Table 7.33.

Table 7.33: SA Power Networks' revised forecast GRN capital expenditure for 2015-20 RCP (June 2015, $ million)

Communications	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Government radio network	1.0	1.0	0.0	0.0	0.0	2.0

7.19 Non-network: Fleet

In its Preliminary Determination, the AER did not accept our fleet capital expenditure forecast of $146.0 (June 2015, $ million) and substituted an alternative estimate of $103.2 (June 2015, $ million).

SA Power Networks does not accept the AER's decision in relation to this expenditure and has included a revised forecast capital expenditure of $122.9 (June 2015, $ million) in this Revised Proposal. Our reasons are explained below.

7.19.1 Rule requirements

Clause 6.5.7(a) of the NER provides that SA Power Networks must submit a building block proposal including a forecast of the capital expenditure it requires to meet the capital expenditure objectives for the 2015-20 RCP. This includes capital expenditure required to comply with all applicable regulatory obligations and requirements.

The AER **must** accept the capital expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied the forecast capital expenditure for the 2015-20 RCP reasonably reflects the capital expenditure criteria. In making this assessment, the AER must have regard to the capital expenditure factors.

The use of vehicles by SA Power Networks' workers is controlled by various regulatory obligations and requirements including:

- the *Work, Health and Safety Act 2012* (SA) (**WHS Act**) and regulations;
- the *Electricity Act 1996* (SA) and regulations;
- the *Road Traffic Act 1961* (SA) and regulations that prescribe vehicle standards, mass, loading requirements and other safety measures in relation to light vehicles; and
- the *Heavy Vehicle National Law* which commenced in South Australia in February 2014 and establishes an independent regulator for all heavy vehicles over 4.5 tonnes gross vehicle mass to administer one set of rules for all heavy vehicles under that law and improve safety and productivity.

7.19.2 SA Power Networks' Original Proposal

In our Original Proposal, we submitted a fleet program of $146.0 (June 2015, $ million) comprising:

- **vehicle replacement** - a base replacement program of $113.8 (June 2015, $ million), which included replacement criteria for:
  - Elevated work platform (**EWP**) vehicles at 10 years;
  - Heavy vehicles at 15 years, which is a shift from 20 years; and
  - Passenger and light commercial vehicles at four years, which is a shift from five years.
- **new fleet** - additional vehicles of $25.6 (June 2015, $ million), driven by the resourcing strategy to deliver the proposed program of work in our Original Proposal; and
- **safety initiatives** - two new safety initiatives driven by WHS requirements of $6.6 (June 2015, $ million), including the roll out of the In Vehicle Management System (**IVMS**) and the installation of vehicle weighing mechanisms at our depots.

Further detail was provided in Attachment 20.26 to the Original Proposal.

7.19.3 AER's Preliminary Determination

The AER rejected our forecast of $146.0 (June 2015, $ million) and established an alternative fleet forecast of $103.2 (June 2015, $ million). In doing this, the AER:

- endorsed our proposed EWP and heavy vehicle replacement criteria;
- rejected the passenger and light commercial criteria change from 5 to 4 years, on the basis that it is more expensive from an NPV perspective (The AER made a $10.6 (June 2015, $ million) adjustment for this change);
- rejected the additional vehicle requirements arising from the resourcing strategy, as the alternative fleet forecast was primarily established on the basis of the 2010-15 RCP forecast expenditure level;
- whilst acknowledging the IVMS roll out has some merit, disallowed it on the basis that insufficient evidence was provided (in the AER's view) to support the need to meet new legislative and WHS requirements; and
- rejected the vehicle weighing system as it deemed that there was no material change to compliance requirements requiring these vehicle weight mechanisms.

7.19.4 SA Power Networks' response to AER Preliminary Determination

Vehicle replacement

We accept the AER's alternative fleet replacement program forecast of $103.2 (June 2015, $ million) noting this reduction reflects the change to a five year replacement criteria for passenger and light commercial vehicles. But we have submitted a different profile to the AER which aligns with the actual timing of our fleet replacement program.

We agree with the AER's endorsement of our EWP and heavy vehicle replacement criteria. Whilst we contend that the shift in the passenger and light vehicle replacement criteria from five to four years is in line with good electricity industry practice, from a technological perspective we accept the AER's preliminary decision to continue to replace these vehicles at five years on a lower cost basis.

New fleet

We do not accept the AER's Preliminary Determination to exclude our forecast capital expenditure for new fleet. As outlined in Section 20.10 of the Original Proposal, the supporting Network Program Deliverability Strategy (Attachment 20.27 to the Original Proposal), and this Revised Proposal, the revised work programs proposed to be undertaken in the 2015-20 RCP are heavily skewed to more labour intensive power line asset replacement and refurbishment works. This work is undertaken by Power Line Trade Skilled Workers (**TSWs**), through a combination of internal and externally outsourced resources.

Based on the revised program of work there will be an increase of approximately 150 TSWs required to deliver the power line related construction and maintenance functions. We have determined that the most prudent and efficient approach is to recruit an additional 75 TSWs over the 2015-20 RCP and outsource the balance. Given a progressive increase in TSWs over the 2015-20 RCP, we will need to invest in additional heavy and light vehicles. This investment is forecast to be $16.7 (June 2015, $ million) over the 2015-20 RCP.

Safety initiatives - IMVS

We do not accept the AER's decision to not make an allowance for expenditure to support the further roll out of the IVMS safety initiative. The first phase of this program has been successfully implemented with the initial roll out of IVMS to 100 vehicles during 2014/15.

The IVMS enables us to ensure (so far as is reasonably practicable) that our workplace is without risk to the health and safety of any person[140] by:

- managing and monitoring the safety and welfare of our mobile employees working alone in remote or risky areas; and
- measuring driver safety and behaviour and vehicle treatment.

IVMS are now being adopted as standard practice in many industries (for example, the mining industry has increased its use of IVMS over the last five years particularly as technology and systems have improved). Like many Australian businesses, the commencement of the WHS Act has triggered SA Power Networks to re-examine its workplace practices and assess whether those workplace practices were sufficient to discharge its duty to ensure that (so far as is reasonably practicable) its workplaces are without risk to the health and safety of any person.

As part of this review process, SA Power Networks took steps to investigate the health and safety benefits which would be derived from the progressive installation of IVMS to its motor vehicle fleet. Those benefits are:

- improved safety and welfare of remote, lone and mobile employees via duress alert and man-down functionality;
- ability to monitor and modify driving behaviour particularly focussing on harsh braking, harsh cornering and excessive acceleration;
- ability to assist with Australian Road Rules compliance eg speeding, seatbelt compliance;
- ability to monitor vehicle treatment;
- clear audit trial for accident investigation; and
- (most importantly) enhanced employee safety by improved driving behaviour and availability of other IVMS functionality.

Given that the cost of implementing IMVS is not grossly disproportionate to the risks that driving vehicles (in rural areas in particular) place on our workers and the public, SA Power Networks identified that this was a reasonably practicable measure and commenced installing IVMS in its motor vehicle fleet during 2014/15.

In its Preliminary Determination, the AER acknowledged the merit of our proposed IVMS initiative but concluded that insufficient evidence was provided to support the need for the IVMS to meet new legislative and WHS requirements.

This conclusion ignores the fact that the installation of IVMS is a measure which is now clearly reasonably practicable to adopt to ensure workplaces are without risk to the health and safety of any person (ie SA Power Networks is obligated to adopt this measure). It does not matter that the WHS Act commenced in 2013 or that the WHS Act does not expressly require the adoption of this safety

[140] *Work, Health and Safety Act 2012* (SA); *Electricity Act 1996* (SA).

measure. What matters is what constitutes a reasonably practicable measure that helps to ensure that our workplaces are without risk to the health and safety of any person at a particular point in time.

The duty under the WHS Act to ensure so far as is reasonable practicable that our workplace is without risk to the health and safety of any person is an objectively determined standard which will change over time as the accepted standard of what is 'reasonable' changes. History shows us that workplace safety has improved over time as new safety measures are adopted and implemented. IMVS is now a safety measure which has been adopted as standard in many industries with similar work place risks to those faced by SA Power Networks' workers and contractors.

The forecast capital expenditure allowance must reflect the capital expenditure criteria including the efficient and prudent costs of achieving the capital expenditure objective of complying with all applicable regulatory obligations and requirements. In this case, what matters is that the installation of IVMS in SA Power Networks' motor vehicle fleet is a reasonably practicable measure that helps to ensure that our workplaces are without risk to the health and safety of any person. This is reflected in our decision to commence the roll out of IVMS during 2014/15.

The introduction of the IVMS by SA Power Networks also followed a number of significant incidents, such as EWP roll overs, which could have resulted in fatalities. Whilst the number of vehicle incidents has remained relatively stable over the last 12 months the severity of these incidents has substantially reduced.

7.19.5 Revised Proposal

Our revised forecast capital expenditure for fleet is $122.9 (June 2015, $ million) as set out in Table 7.34.

This revised forecast takes into account:

- the AER's alternative fleet replacement program;
- incorporating the AER's decision not to shift the passenger and light commercial replacement criteria from five to four years which has reduced the number of these vehicles being replaced in the 2015-20 RCP and led to a corresponding decrease in the number of IVMS units being installed in the fleet; and
- installing the IVMS across our fleet.

Table 7.34: SA Power Networks' revised Vehicles capital expenditure for the 2015-20 RCP (June 2015, $ million)

Vehicles	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Vehicle replacement	34.0	19.2	13.6	16.8	19.6	103.2
New fleet	1.9	3.6	4.0	3.7	3.5	16.7
Safety – IVMS	0.7	1.1	1.2	0.0	0.0	3.0
Total	**36.6**	**23.9**	**18.8**	**20.5**	**23.1**	**122.9**

7.20 Non-network: Buildings and Property

In its Preliminary Determination, the AER did not accept our proposed buildings and property capital expenditure forecast of $111.6 (June 2015, $ million) and included an alternative estimate of $71.8 (June 2015, $ million). An additional allowance of $2.4 (June 2015, $ million) for easements was included in the total network capital expenditure allowance.

SA Power Networks does not accept the AER's decision in relation to this expenditure and has included a revised forecast capital expenditure of $91.7 (June 2015, $ million) in this Revised Proposal. Our reasons are explained below.

7.20.1 Rule requirements

The provision of fit-for-purpose, functional, safe and compliant property is paramount to ensure our employees have the right facilities available to them and that these facilities meet modern standards, comply with all regulatory obligations and requirements and provide a safe work environment.

7.20.2 SA Power Networks' Original Proposal

In our Original Proposal, we submitted a buildings and property program of $111.6 (June 2015, $ million), which comprised:

- property refurbishment, upgrades and depot rebuilds required to address the outcomes of our comprehensive, location, functionality, condition and compliance based assessments;
- the expansion and construction of a minimal number of depots to address forecast employee growth associated with delivering the programs of works proposed to be undertaken over the 2015-20 RCP; and
- easement costs relating to customer connection requests for the extension of the network.

Further detail was provided in Attachment 16.7 to the Original Proposal.

7.20.3 AER's Preliminary Determination

In its Preliminary Determination, the AER rejected our proposed forecast of $111.6 (June 2015, $ million) and included an alternative forecast of $71.8 (June 2015, $ million), excluding easements for the following reasons:

- the methodology adopted by SA Power Networks to rationalise the buildings and property program was deemed not to be a 'systematic and transparent optimisation process that might justify the prudence and efficiency of the proposed works program';[141]
- whilst the supporting business cases for major building and property investments provided some justification, they were generally lacking in detail, particularly in respect to economic analysis;
- the alternative forecast of $71.8 (June 2015, $ million), excluding easements, was established primarily on the basis of the 2010-15 RCP forecast expenditure level; and
- a network adjustment factor[142] was applied to reduce easement costs to $2.4 (June 2015, $ million).

---

[141] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-125.
[142] AER, *Preliminary Decision: SA Power Networks distribution determination 2015-16 to 2019-20,* April 2015, (model).

7.20.4 SA Power Networks' response to AER Preliminary Determination

Land and buildings

We do not accept the AER's decision to not provide additional funding beyond a base program level of \$71.8 (June 2015, \$ million) excluding easements, for investment in buildings and property associated with our forecast employee growth.

As outlined in Section 20.10 of the Original Proposal and the supporting Network Program Deliverability Strategy (in Attachment 20.27 to the Original Proposal), the revised work programs proposed to be undertaken in the 2015-20 RCP are heavily skewed to more labour intensive power line asset refurbishment works. This work is undertaken by Power Line Trade Skilled Workers (**TSWs**), through a combination of internal and externally outsourced resources above current baseline levels. Based on the revised program there will be an increase of approximately 150 TSWs required to deliver the power line related construction and maintenance functions. We have determined that the most prudent and efficient approach is to recruit an additional 75 TSWs over the 2015-20 RCP and outsource the balance.

Given this progressive increase in TSWs over the 2015-20 RCP, we need to, as a minimum, construct a new depot at Seaford (outer southern metropolitan area) and a larger depot at Nuriootpa (outer northern metropolitan area). These projects will be undertaken in the first half of the 2015-20 RCP at a forecast cost of \$8.8 (June 2015, \$ million) and \$7.9 (June 2015, \$ million) respectively.

This expenditure is a material cost that we will need to be incurred in the 2015-20 RCP in order to comply with our regulatory obligations and requirements.

As set out in clauses 6.5.7(a) and (c) of the NER , the forecast capital expenditure allowance must reflect the capital expenditure criteria including the efficient and prudent costs of achieving the capital expenditure objective of complying with all applicable regulatory obligations and requirements. We have therefore added the costs of these properties to the AER's base program forecast of \$71.8 (June 2015, \$ million) to arrive at the land and buildings forecast of \$88.5 (June 2015, \$ million).

Easements

We do not accept the AER's decision in relation to the application of an adjustment factor to easement costs. These costs are directly related to customer connection requests and are a material cost that SA Power Networks will incur during the 2015-20 RCP. Given that the AER approved the capital connections forecast in its Preliminary Determination, it follows that the easement costs should also be allowed in full.

7.20.5 Revised Proposal

Our revised forecast for buildings and property is \$91.7 (June 2015, \$ million) as set out in Table 7.35. This represents a reduction compared to our Original Proposal as it incorporates the AER's alternative base program forecast for buildings and property.

Table 7.35: SA Power Networks' revised Property capital expenditure for the 2015-20 RCP (June 2015, $ million)

Property	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Land	0.1	0.0	0.0	0.0	0.0	0.1
Buildings	18.0	24.1	17.6	14.4	14.3	88.4
Easements	0.6	0.6	0.6	0.7	0.7	3.2
Total	**18.7**	**24.7**	**18.2**	**15.1**	**15.0**	**91.7**

7.21 Non-network: Other (Distribution network pricing rule change)

In our Original Proposal, SA Power Networks submitted forecast capital and operating expenditure associated with the introduction of cost-reflective network tariffs for small customers. In its Preliminary Determination, the AER did not approve this expenditure.

7.21.1 Rule requirements

The AEMC's Distribution Network Pricing Arrangements Rule change was finalised in November 2014 and set a timeframe for new cost-reflective tariffs based on the new pricing principles to be in place from 1 July 2017 in South Australia.

7.21.2 SA Power Networks' Original Proposal

In our Original Proposal, we proposed a transition path to cost-reflective network tariffs for residential and small customers, consistent with our expected regulatory obligations under the pricing principles in the new Rules (that were in draft at the time that our Original Proposal was submitted to the AER).

We proposed:

- to phase in a new residential tariff based on monthly peak demand for small market customers;
- to make the new tariff available on an opt-in basis initially, becoming mandatory for all new customers and customers upgrading their supply arrangements (eg to install 3-phase power, solar PV systems, etc) from July 2017;
- to discontinue installing basic accumulation meters, and to install interval-capable meters as standard, from July 2015, to facilitate uptake of the new tariff;
- to move from quarterly meter reading to monthly meter reading for customers taking on the new tariff initially, and for all customers from July 2017. Monthly meter reading enables accurate monthly billing so that customers can respond effectively to the monthly price signal in the new tariff. The economies of manual meter reading are such that, as customers move to the new tariff, it quickly becomes more cost-efficient to transition to monthly reading for all customers than to maintain separate read routes for monthly- and quarterly-read customers; and
- to undertake a comprehensive customer and retailer engagement program to ensure that customers and retailers understand the tariff, and to support customers in responding to the new price signals.

7.21.3 AER's Preliminary Determination

In its Preliminary Determination, the AER did not agree with our proposal to install interval meters as standard, nor did it approve our proposal to move to monthly meter reading. The AER took the view that the associated costs were unwarranted given the retailer-led rollout of smart meters expected to commence from 2017 under the new regulatory framework proposed in the AEMC's draft Rule change on Expanding Competition in Metering and Related Services that was published in March 2015.

The AER went on to reject all of our proposed expenditure associated with the introduction of cost-reflective tariffs, on the grounds that our proposed approach to tariff reform was dependent on our metering proposal, which the AER had not approved.

7.21.4 SA Power Networks' response to AER Preliminary Determination

We do not agree with the AER's decision to reject all expenditure related to the introduction of cost-reflective network tariffs. We now have a mandatory regulatory obligation to phase in cost-reflective pricing in the 2015-20 RCP under the new pricing principles in the NER, and will need to incur additional new expenditure as a result that regulatory change.

While we do not agree with the AER's analysis of the costs and benefits of installing upgradable interval meters, we accept the AER's preliminary decision in relation to our metering proposal, and no longer propose to install interval meters as standard.

Our concerns with the AER's Preliminary Determination primarily relate to the following areas:

- the requirement to transition to cost-reflective tariffs;
- cost-reflective tariffs to be phased in from 2017;
- a tariff based on maximum demand; and
- customer and retailer engagement.

The requirement to transition to cost-reflective tariffs

The new distribution network pricing principles recognise that a transition to more cost-reflective network tariffs is required to address inequitable and unsustainable cross-subsidies that result from tariffs that are levied on energy consumption as is the norm for small customers today.

If we do not adopt cost-reflective pricing, growing cross-subsidies will mean that by 2034 a customer without access to solar PV or other distributed energy resources (DER) will be paying roughly 50% more in network charges than a customer who has adopted DER, for the same network service.[143]

The current network pricing structures are not in the long term interest of customers. With the proper price signals, emerging technologies such as battery storage and electric vehicles present opportunities for customers to flatten their load profiles and thus increase utilisation of, and hence community value from, existing network assets.

Conversely, in the absence of cost-reflective network tariffs, customer adoption of these emerging technologies could drive renewed growth in peak demand and the need for increased network infrastructure augmentation.

Cost-reflective tariffs to be phased in from 2017

The AEMC's final determination on the Distribution Network Pricing Rule change set a timeframe for new cost-reflective tariffs based on the new pricing principles to be in place from 1 July 2017 in South Australia.[144] Our Original Proposal was entirely consistent with this timeframe.

At the time that we submitted our Original Proposal it was expected that customers would begin to adopt smart meters on an 'opt in' basis at some point midway through the 2015-20 RCP when the proposed new rules for metering competition came into effect. There was, however, considerable uncertainty regarding the detail of the new rules and the timing, pace and reach of the anticipated 'market led' smart meter rollout. As a consequence, we did not consider it prudent to rely on an

---

[143] SA Power Networks' *Regulatory Proposal 2015-20*, Attachment 5.3 A*ssessment of Future Tariff Scenarios for South Australia*, report prepared by Energeia for SA Power Networks, July 2014.
[144] SA Power Networks' *Regulatory Proposal 2015-20*, Attachment 14.3 *Tariff & Metering Business Case*, section 6.4.3.

unquantified future deployment of smart meters by other parties in South Australia in order to achieve our regulated obligations with regard to network tariff reform. We also did not consider it to be in the interests of our customers to continue to install non-upgradable 'dumb' accumulation meters knowing they would not support the tariffs we are required to introduce, and hence have to be replaced within a few years, exposing customers to unnecessary cost and the inconvenience of another power outage.

In March 2015 the AEMC published the draft Rule on Expanding Competition in Metering and Related Services. The draft Rule departs from the original concept of a 'customer led' opt-in smart meter rollout, and proposes instead that all meters installed from July 2017 must be smart meters, with customers able to opt out only in very limited circumstances.[145] This in turn means that all new and upgrade customers from July 2017 can be moved to cost-reflective network tariffs at the time that they are making demand-side investments – precisely the outcome that our Original Proposal was intended to achieve.[146]

While we do not agree with the AER's view that it is in our customers' interests to continue to install obsolete meters, we are now confident that the metering competition rule change will achieve a transition to interval metering in the timeframe required to enable network tariff reform. We therefore accept the AER's Preliminary Determination regarding metering, and no longer propose to install interval meters as standard.

The AER's decision to reject our proposal to install interval meters as standard does not, however, diminish the need for tariff reform or our responsibilities under the new rules.

A tariff based on maximum demand

The AEMC estimates that up to 81% of consumers would face lower network charges in the medium term under a cost-reflective network price, and finds that pricing based on maximum demand (capacity) is more beneficial than alternatives such as critical peak pricing.[147]

This finding aligns with SA Power Networks' own analysis of the likely impact on customer behaviour of different tariff structures, which compared capacity-based tariffs against Time of Use (**ToU**) and Critical Peak Pricing (**CPP**) tariffs.[148] This has found that the price signal inherent in ToU tariffs is too weak in the South Australian context to deliver material change in customer behaviour during the small number of extreme demand days associated with summer heatwaves. CPP, on the other hand, has the potential to provide a stronger price signal, but has been ruled out after an analysis of historical data suggested that the number of 'critical peak' event days is likely to vary significantly year-on-year due to South Australia's highly variable summer weather patterns, leading to excessive revenue and bill volatility.

Our proposal to phase in cost-reflective tariffs more broadly in the residential and small business segments by making the maximum demand tariff mandatory for all new and upgrade customers from July 2017 is, therefore, not only consistent with the new pricing principles in the NER with which we must abide, but is also consistent with our long-term approach to tariff reform.

Customer and retailer engagement

In its Preliminary Determination the AER stated that:

---

[145] AEMC, *Expanding competition in metering and related services*, March 2015.
[146] SA Power Networks', *Regulatory Proposal 2015-20*, Attachment 14.3 Tariff & Metering Business Case, section 3.3.
[147] AEMC Rule Determination, Distribution Network Pricing Arrangements, November 2014.
[148] SA Power Networks', *Regulatory Proposal 2015-20*, Attachment 14.3 Tariff & Metering Business Case, section 3.1.

> *'We accept that SA Power Networks may incur some additional consultation costs in developing its new tariff structures. For instance, the structure of its tariff must be reasonably capable of being understood by retail customers so SAPN may incur some additional costs in meeting this requirement.'*[149]

We agree with the AER's statement that SA Power Networks is likely to incur additional costs in introducing cost-reflective tariffs. For this reason we disagree with the AER's decision to exclude all such costs in its Preliminary Determination.

Customers have become accustomed to the fact that their electricity costs are directly related to the total amount of energy they consume, and generally understand how to save energy in order to save money. Market research undertaken as part of SA Power Networks' capacity tariff trials in 2013 and 2014[150] has shown that customers, in general, are not aware that their peak demand also has an impact on costs, and do not know what their peak demand is or how to manage it.

In our Original Proposal we proposed an extensive customer engagement program to ensure customers are provided with the information, tools and support they require to understand the new tariffs and respond to the price signals in them. We also proposed that retailers would require education and support to enable them to incorporate the tariff in their product offerings, and understand the potential impacts on customers. This operating capital expenditure item is discussed in further detail in Chapter 8, Section 8.17.

Our response is discussed in more detail in Attachment G.22: *Distribution Pricing rule change*.

7.21.5 Revised Proposal

Our Revised Proposal includes expenditure to support the introduction of cost reflective tariffs is $2.6 (June 2015, $ million), as set out in Table 7.36.

We propose to phase in cost-reflective network tariffs based on maximum demand in the 2015-20 RCP, making the new tariffs mandatory from July 2017 for all customers who have a smart meter installed from July 2017.

The interval metering required to support these tariffs will be provided for by the AEMC's Expanding Competition in Metering and Related Services Rule change which is due to be finalised in July 2015 and will make interval meters mandatory for all new installations and meter replacements from 1 July 2017.

Our Revised Proposal aligns the new pricing principles established in the AEMC's Distribution Network Pricing Rule change made in November 2014, a mandatory regulatory obligation and the AEMC's required timeframe for transition to cost-reflective tariffs.

For further information refer to Attachment G.22 – *Distribution pricing rule change*.

---

[149] AER, *Preliminary Determination*, Attachment 7 page. 7-86.
[150] 3 SA Power Networks', *Regulatory Proposal 2015-20*, Attachment 14.*Tariff & Metering Business Case.*

Table 7.36: SA Power Networks' revised distribution network pricing rules capital expenditure for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Total	1.5	1.1	0.0	0.0	0.0	2.6

There is also an operating cost associated with the Distribution Pricing Rule change. Refer to Section 8.17 of this Revised Proposal.

7.22 Escalations

In its Preliminary Determination, the AER reduced SA Power Networks' real cost escalation forecasts for labour and applied zero per cent cost escalation to materials. This resulted in a reduction in capital expenditure allowances of $36.8 (June 2015, $ million).

7.22.1 Rule requirements

Clause 6.5.7(c) of the NER provides that the AER **must** accept our capital expenditure forecast if the AER is satisfied that the total of the forecast capital expenditure for the RCP reasonably reflects the capital expenditure criteria, which are:

1) the efficient cost of achieving the capital expenditure objectives; and
2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and
3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

Real cost escalation forecasts represent a cost input that SA Power Networks will incur over the 2015-20 RCP in achieving the capital expenditure objectives.

7.22.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks submitted total real cost escalation of $98.1 (June 2015, $ nominal) for capital expenditure, based on the following escalators:

Table 7.37: Original Proposal - Real Price Escalators

Input Category	Escalation Basis
Labour	Forecasts based on actual Enterprise Agreement (**EA**) outcomes for the first two years of the 2015-20 RCP and forecasts prepared by Frontier Economics based on a peer comparator group for the remaining three years.
Contract Services	Forecasts prepared by BIS Shrapnel of the South Australian Construction Industry Wages Price Index (**WPI**).
Materials	Forecasts of escalation and weightings of commodity prices prepared by Competition Economists Group (**CEG**) and Jacobs.
Land	Forecasts prepared by Maloney Field Services based on unimproved land values.

7.22.3 AER's Preliminary Determination

In its Preliminary Determination, the AER rejected SA Power Networks' proposed labour escalation based on EA outcomes and substituted them with rates forecast by Deloitte Access Economics (**DAE**) of the electricity, gas, water and waste services (**EGWWS**) industry WPI.

The AER also rejected SA Power Networks' forecasts for real cost escalation of materials in its Preliminary Determination. It considered that zero per cent real cost escalation '*is reasonably likely to* *reflect a realistic expectation of the cost inputs required to achieve the capex objectives over the 2015-20 RCP.'*[151]

7.22.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks is of the view that the AER has not had due regard to our regulatory obligations and requirements in relation to our EA, the limitations of the EGWWS WPI based forecasts and the advantages of the EA based approach. Our EA based labour cost forecasts best represent the annual change in labour price for our electricity distribution workers and therefore best satisfy the requirements of the capital expenditure criteria in that they reflect the efficient and realistic costs that SA Power Networks expects to prudently incur in the provision of network services.

In its Revised Proposal, SA Power Networks resubmits its forecast of labour cost escalation on EA based rates. Further detail is provided in Section 8.9.3 of this Revised Proposal.

SA Power Networks accepts the AER's preliminary decision to apply zero percent real cost escalation to materials for the 2015-20 RCP.

In its Preliminary Determination, the AER accepted SA Power Networks' forecast of its capital expenditure real cost escalators for contracted services, finding them:

> *'likely to more reasonably reflect a realistic expectation of the cost inputs required to achieve the capex criteria given that they are direct inputs into the cost of providing network services.'*[152]

SA Power Networks accepts the AER's preliminary decision in relation to capital expenditure real cost escalators for contracted services.

7.22.5 Revised Proposal

SA Power Networks has reviewed the AER's approach to determining labour cost escalators and considers that it does not provide a realistic expectation of cost inputs required to meet the capital (and operating) expenditure objectives during the 2015-20 RCP and hence does not provide a reasoned basis for SA Power Networks to change its approach to forecasting its labour cost escalators.

In our Revised Proposal, SA Power Networks has re-applied labour cost escalation to capital expenditure based on:

- current EA outcomes for the first two regulatory years of the 2015-20 RCP; and
- an extrapolation of benchmarked EA outcomes from similar businesses based on analysis from Frontier Economics in the remaining regulatory years of the 2015-20 RCP.

Further detail is provided in Section 8.9.3 of this Revised Proposal.

SA Power Networks accepts the AER's preliminary decision to apply zero per cent real cost escalation to materials for the 2015-20 RCP.

[151] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-143.
[152] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-143.

7.23 Revised Regulatory Proposal

SA Power Networks' revised forecast total capital expenditure for the provision of SCS is $2,083.4 (June 2015, $ million), as set out in Table 7.39.

Table 7.39: SA Power Networks' revised SCS forecast net capital expenditure by driver for the 2015-20 RCP (June 2015, $ million)

Standard Control Services	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Replacement	128.3	145.8	152.0	154.4	151.4	**731.8**
Augmentation	127.4	144.2	137.7	123.1	102.7	**635.1**
Connections						
Customer connections (gross)	136.3	138.9	141.7	149.1	157.0	**723.1**
Customer contributions	(102.2)	(102.5)	(104.3)	(109.0)	(114.2)	**(532.2)**
Customer connections (net)	34.1	36.4	37.5	40.1	42.8	**190.8**
Non Network	119.4	118.0	96.4	94.1	85.1	**513.0**
Total SCS expenditure forecast (net)	**409.1**	**444.4**	**423.5**	**411.7**	**382.0**	**2,070.8**
Equity raising	12.4	-	-	-	-	12.4
Total (incl equity raising	**421.6**	**444.4**	**423.5**	**411.7**	**382.0**	**2,083.2**

Page left blank intentionally

8. Forecast operating expenditure

In its Preliminary Determination, the AER did not accept SA Power Networks' proposed forecast operating expenditure, excluding debt raising costs, of $1,527.1 (June 2015, $ million) for the provision of standard control services (**SCS**). The AER was not satisfied that our proposed forecast operating expenditure reasonably reflected the operating expenditure criteria. The AER determined a substitute estimate of $1,225.8 (June 2015, $ million), excluding debt raising costs and Demand Management Incentive Allowance (**DMIA**), which represents a 20% reduction from SA Power Networks' proposed operating expenditure forecast.

In this chapter of our Revised Proposal, we explain our revised operating expenditure forecast of $1,421.9 (June 2015, $ million), excluding debt raising costs and DMIA, for the provision of SCS for the 2015-20 RCP. SA Power Networks has prepared this revised forecast taking into consideration the AER's Preliminary Determination, public submissions on SA Power Networks' Original Proposal and further refinement of our program criteria and forecasting methodologies.

8.1 Rule requirements

Clause 6.5.6(a) of the NER provides that SA Power Networks must submit a building block proposal that includes a forecast of the operating expenditure it requires to meet each of the following operating expenditure objectives for the 2015-20 RCP, which are to:

1) meet or manage the expected demand for SCS over that period;
2) comply with all applicable regulatory obligations or requirements associated with the provision of SCS;
3) to the extent that there is no applicable regulatory obligation or requirement in relation to:
    a. the quality, reliability or security of supply of SCS; or
    b. the reliability or security of the distribution system through the supply of SCS,

to the relevant extent:

    c. maintain the quality, reliability and security of supply of SCS;
    d. maintain the reliability and security of the distribution system through the supply of SCS; and

4) maintain the safety of the distribution system through the supply of SCS.

Clause 6.5.6(c) of the NER provides that the AER must accept the proposed operating expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied that the forecast operating expenditure for the 2015-20 RCP reasonably reflects the operating expenditure criteria, which are:

1) the efficient costs of achieving the operating expenditure objectives;
2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and
3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

Finally, clause 6.5.6(e) of the NER provides that, in making this assessment, the AER must have regard to the operating expenditure factors which include, but are not limited to, benchmarking, historical performance, substitution possibilities between operating and capital expenditure, and importantly

> *'the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the DNSP in the course of its engagement with electricity consumers'*[153] ***(Consumer Engagement Factor)***

8.2 SA Power Networks' Original Proposal

In our Original Proposal we explained that our actual operating expenditure for the 2010-15 RCP was in line with the allowances accepted by the AER in its 2010 Determination. We also outlined that our proposed SCS operating expenditure forecast for the 2015–20 RCP has been developed on a 'base-step-trend' approach, where:

- the 'base' represents the efficient 2013/14 regulatory year, adjusted for unusual items, plus the incremental change between the 2013/14 and 2014/15 allowances;
- the 'step' represents the changes in the scope of activities carried out in the delivery of SCS which are not reflected in the base year; and
- the 'trend' represents the changes in the scale (output growth) and the escalation of labour and non-labour costs (real price growth) applied to the SCS expenditure categories.

Table 8.1 sets out the SCS operating expenditure forecast of $1,527.1 (June 2015, $ million), excluding debt raising costs, included in our Original Proposal.

Table 8.1: Original Proposal SCS forecast operating expenditure for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Base	247.4	247.4	247.4	247.4	247.4	**1,237.0**
Base year	(8.4)	(8.6)	(6.8)	(4.6)	(6.4)	**(34.8)**
Step changes	35.9	42.0	48.8	46.4	43.7	**216.8**
Output growth	3.0	6.1	9.4	12.6	15.6	**46.7**
Real price growth	3.0	6.9	11.7	17.0	22.8	**61.4**
Total	**280.9**	**293.8**	**310.5**	**318.8**	**323.1**	**1,527.1**

Note: Excludes debt raising costs.

Source: SA Power Networks Regulatory Proposal 2015-20, page 253, Table 21.1.

[153] Clause 6.5.6(e)(5A) of the NER.

Consistent with the approach we adopted in relation to our Original Proposal as a whole, our forecast of total SCS operating expenditure was designed to deliver optimal service provision for our customers in both the short term and long term.

To ensure consistency with the National Electricity Objective and the requirements of the NER, this service program took account of key operating environment factors, including:

- the need to comply with all applicable regulatory obligations and requirements, including those relating to safety (of the network infrastructure and its operation), service standards and asset management practices;
- emerging changes in applicable regulatory obligations and requirements, including but not limited to Power of Choice reform program developments that reflect significant changes in how the distribution network will operate in the future;
- ongoing rapid connection rates of new customer technologies such as solar photo-voltaic (**PV**) panels; and
- ongoing changes in customers' expectations concerning various aspects of our services to them.

We have been proactive and thorough in addressing these factors including through unprecedented efforts to capture and understand customer and stakeholder perspectives concerning many of these factors throughout the course of our Customer Engagement Program (**CEP**). Our CEP was discussed at Chapter 3 of this Revised Proposal.

Our Original Proposal also went to great lengths to explain how our operating (and capital) expenditure forecasts relate to our many areas of service provision to our customers.

This was achieved through a series of chapters (Chapters 9 to 16 in our Original Proposal) that addressed the individual service areas, applicable regulatory obligations and requirements, current and emerging issues relevant to the area, CEP feedback, and how we addressed the CEP feedback in our forecasts. The chapters, and the key links to our operating expenditure forecasts, are shown in Table 8.2.

Table 8.2: How our Original Proposal addressed customer concerns

Original Proposal chapter	Key links to our operating expenditure forecasts
Chapter 9 'Keeping the power on for South Australians'	Network inspections, safety operations and asset management, substation maintenance
Chapter 10 'Responding to severe weather events'	Telecommunications network
Chapter 11 'Safety for the community'	Bushfire risk mitigation, asset inspections
Chapter 12 'Growing the network in line with South Australia's needs'	National Energy Customer Framework customer charging changes
Chapter 13 'Ensuring power supply meets voltage and quality standards'	Flexible load management
Chapter 14 'Serving customers now and in the future'	IT systems supporting billing, customer service and cost reflective tariffs
Chapter 15 'Fitting in with our streets and communities'	Vegetation management
Chapter 16 'Capabilities to meet our challenges'	IT systems supporting workplace safety, property, vehicle fleet and other operating environment changes

From an examination of the content of these chapters in the Original Proposal (and numerous other components of our Original Proposal), it is self-evident that our Original Proposal provided significant evidence in terms of how our operating (and capital) expenditure forecasts addressed the concerns of our customers.

8.3 AER's Preliminary Determination

In accordance with clauses 6.5.6(d) and 6.12.1(4)(ii) of the NER, the AER has not accepted the total forecast operating expenditure proposed by SA Power Networks for the provision of SCS during the 2015-20 RCP, and has set out its reasons for this decision in its Preliminary Determination.

The AER's preliminary decision is that SA Power Networks' SCS forecast operating expenditure of $1,527.1 (June 2015, $ million) for the 2015-20 RCP did not reasonably reflect the operating expenditure criteria. The AER determined a substitute estimate of our total forecast operating expenditure of $1,225.8 (June 2015, $ million), excluding DMIA, which it believed more reasonably reflected the operating expenditure criteria. Table 8.3 outlines the AER's preliminary decision compared to SA Power Networks' Original Proposal.

Table 8.3: AER Preliminary Determination - SCS operating expenditure costs for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Original Proposal	280.9	293.8	310.5	318.8	323.1	**1,527.1**
AER preliminary decision	240.5	243.0	245.1	247.4	249.7	**1,225.8**
Difference	-40.4	-50.8	-65.4	-71.4	-73.4	**-301.3**
% Difference	-14%	-17%	-21%	-22%	-23%	**-20%**

Note: Excludes debt raising costs.

Preliminary decision excludes DMIA of $3m, which was included in our Original Proposal forecast.

Source: AER, Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20, April 2015, Table 7.2

In making its preliminary decision, the AER accepted the base year operating expenditure as it deemed it to be not materially inefficient, based on its benchmarking. The AER acknowledged that there were valid reasons for the increase in operating expenditure, and the decline in productivity, over the benchmarked 2006-2013 period, particularly as this was a consistent trend across all DNSPs.

The key areas of difference between SA Power Networks' original operating expenditure proposal and the AER's substitute estimate are as follows:

Step Changes

- step changes of only $9.1 (June 2015, $ million) were accepted by the AER, as compared with the $216.8 (June 2015, $ million) proposed by SA Power Networks. The AER only accepted two step changes:
  - the regulatory changes associated with the implementation of the National Energy Customer Framework (**NECF**) forecast at $1.3 (June 2015, $ million); and
  - the mobile radio capital expenditure/operating expenditure trade-off forecast at $7.8 (June 2015, $ million);
- a proposed base year adjustment for the reduction in the distribution licence fee was accepted by the AER and classified as a step change adjustment of -$5.0 (June 2015, $ million);[154] and
- the AER outlined a number of reasons for rejecting the remaining step changes, including that, in its view:
  - the base year operating expenditure is sufficient to meet existing legal and regulatory requirements, and therefore funds will not be provided for additional activities required to meet compliance;
  - there was little evidence that regulations or requirements had changed since the 2013/14 base year;

[154] The Original Proposal reduction adjustment of $5.5 million, was subsequently changed to a $5.0 million reduction based on advice from the South Australian Minister for Mineral Resources and Energy.

- step changes for initiatives designed to achieve efficiencies, such as IT programs, would not be funded as this would be inconsistent with the incentive schemes; and
- there was no compelling evidence to support customer driven programs, such as vegetation management initiatives.

Rate of Change - Output Growth

- output growth of $20.5 (June 2015, $ million) was determined, as compared to $46.7 (June 2015, $ million) proposed by SA Power Networks;
- SA Power Networks' proposed output growth for the 2015-20 RCP was based on a similar model to the one approved by the AER in its 2010 Determination;[155] and
- the AER applied output growth measures and weightings used in Economic Insights' economic benchmarking report and used data from SA Power Networks' Reset RIN.[156] As a result, the AER applied no output growth escalation, despite clear evidence that efficient augmentation of our distribution network will continue to be required during the 2015-20 RCP (due to spatial demand growth, whilst aggregate demand remains flat).

Rate of Change - Real Price Growth

- real price growth of $5.9 (June 2015, $ million) was determined, as compared with $61.4 (June 2015, $ million) proposed by SA Power Networks;
- the AER did not accept SA Power Networks' proposed real price escalators based on our Enterprise Agreements (**EA**) and consultants' forecasts of labour, materials, contracted services and land associated costs; and
- the AER adopted a 62% weighting for labour and 38% for non-labour, and applied Deloitte Access Economics' (**DAE**) forecast of the Wages Price Index (**WPI**) for the Electricity, Gas, Water and Waste Services (**EGWWS**) industry sector to labour, with no real price escalation applied to non-labour.

Productivity Adjustment

- the AER applied a zero per cent productivity growth in its overall rate of change, consistent with that proposed in SA Power Networks' Original Proposal. We note that the AER's preferred econometric modelling identified negative productivity growth across the industry.

The AER determined a substitute estimate of $1,225.8 (June 2015, $ million) for operating expenditure for SCS, as shown by driver in Table 8.4. Whilst the substitute estimate has been categorised into specific components (eg base year, rate of change), the AER has made it clear that the preliminary decision concerns SA Power Networks' total forecast operating expenditure.

---

[155] SA Power Networks, *Regulatory Proposal 2015–20*, October 2014, page 264-265.
[156] AER, *Preliminary Decision: SA Power Networks' determination 2015-16 to 2019-20*, April 2015, page 7-22.

Table 8.4: AER Preliminary Decision SCS forecast operating expenditure for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Adjusted base year	239.1	239.1	239.1	239.1	239.1	1,195.3
Step changes	0.3	0.8	0.9	1.0	1.1	4.1
Output growth	1.3	2.7	4.1	5.5	6.9	20.5
Real price growth	-0.1	0.4	1.1	1.8	2.7	5.9
Total SCS operating expenditure forecast*	**240.5**	**243.0**	**245.1**	**247.4**	**249.7**	**1,225.8**

* Does not add due to rounding

The following sections of this chapter describe SA Power Networks' revised operating expenditure forecasts for those areas of the AER's Preliminary Determination that SA Power Networks considers must be amended in the AER's Final Determination.

8.4 SA Power Networks' response to AER Preliminary Determination

Sections 8.6 to 8.25 of this chapter provide details of SA Power Networks' response to the AER's Preliminary Determination with respect to our base year, rate of change and step changes under the base-step-trend approach.

However, before discussing these matters in detail, some introductory remarks are appropriate to outline how the AER has erred by failing to give due consideration to important aspects of our Original Proposal which are relevant to the AER's consideration of this Revised Proposal. Specifically:

- SA Power Networks will face material and on-going increases in costs;
- SA Power Networks is already efficient; and
- the EBSS will not assist in meeting growing costs.

SA Power Networks will face material and on-going increases in costs

The AER has emphasised that an efficient DNSP should be able to adopt new business practices without increasing overall levels of expenditure. While this may be true to some extent, it does not address the situation where an efficient firm is facing real increases in its cost inputs, or the need for material and on-going increases in expenditure in order to meet demand, satisfy customer expectations, or comply with regulatory obligations and requirements.

In that situation, the efficient firm cannot simply find the money elsewhere. Something else that it has been doing – ie works that were considered to be prudent and efficient - must be curtailed in order to meet growing costs over the next RCP. An expenditure allowance that forces an efficient DNSP into this position is not one that complies with the operating expenditure criteria.

SA Power Networks is already efficient

SA Power Networks has been found by the AER to be one of the most efficient DNSPs through the AER's benchmarking process. Indeed, had environmental factors been considered (most significantly for capitalisation policy) SA Power Networks would have benchmarked well ahead of the initial efficient frontier identified by the AER.

In its Final Determinations for the NSW and ACT DNSPs, the AER has moved the benchmark back to the bottom of the upper quartile. This has effectively reduced the burden on less efficient DNSPs to reach the benchmark. On a like for like basis, and as a result of the movement in the benchmark, SA Power Networks could have actually incurred much higher expenditure in its base year and still have been deemed to be an efficient firm.

The point is that there is no inefficiency in SA Power Networks that can easily be removed in order to free up funds to respond to growing costs. The AER has acknowledged that it is more difficult for an efficient firm to make efficiency gains than it is for inefficient firms.[157] The inefficient firm can improve efficiency through business practices already adopted by the more efficient firms. In contrast, the firm at the efficiency frontier finds it much harder to make material gains in efficiency. This is the position in which we now find ourselves.

[157] AER, *Draft decision - Ausgrid distribution determination 2014–19*, November 2014, page 7-144.

The EBSS will not assist in meeting growing costs

While the AER will apply the EBSS to SA Power Networks in the 2015-20 RCP to provide a further incentive to improve efficiency, the value of this incentive will be severely eroded by the AER's refusal to allow increases in expenditure allowances to meet growing costs. The benefits of any efficiency improvements will be absorbed by the need to meet cost increases, rather than being reflected in lower revealed costs. Indeed the EBSS will penalise SA Power Networks if it is unable to improve efficiency to meet growing costs, especially where those costs are beyond its control. In this context, we note that the EBSS will not include exemptions for any new uncontrollable costs that may arise during the 2015-20 RCP; this will further add to the risk of SA Power Networks being exposed to EBSS penalties. This effectively creates an asymmetric EBSS contrary to the Incentives Guidelines.

In view of what is set out above, and the detailed comments provided in Sections 8.6 to 8.25 of this chapter, we believe the AER has failed to give due consideration to:

- the growth in cost inputs that SA Power Networks will face over the 2015-20 RCP;
- expenditure that will be required to comply with regulatory obligations and requirements over the 2015-20 RCP;
- expenditure that will be required to address the concerns of electricity consumers identified in the course of our CEP;
- our position as one of the most efficient DNSPs in the NEM and our inability to achieve further substantial efficiency gains in the 2015-20 RCP; and
- the failure of the EBSS to reward further efficiency improvements.

The cost escalators and step changes sought by SA Power Networks in this Revised Proposal are crucial to delivering an expenditure forecast that reflects the prudent and efficient costs of meeting the operating expenditure objectives.

We consider that our Revised Proposal meets all of the requirements of the operating expenditure objectives and criteria under clauses 6.5.6 (a) and (c) of the NER as:

- our output growth and real price escalation are based on predicted demand and realistic, independently derived forecasts, including the latest demand forecasts from AEMO;
- our base year costs have been determined to be efficient - we are benchmarked as one of the most efficient DNSPs, and our operating expenditures in the 2010-15 RCP have been in line with regulatory allowances;
- increases in operating expenditure in the 2010-15 RCP have been driven primarily by the requirement to maintain reliability and security of supply as a result of exogenous factors, such as additional vegetation management associated with the breaking of the millennium drought and an increase in the volume and severity of weather related events;
- our productivity growth, which includes the above expenditure increases, is consistent with industry trends; and
- our proposed step changes are prudent and efficient and are required to meet our regulatory obligations and requirements and the expectations and requirements of electricity consumers.

We believe we have clearly demonstrated that we will face growth in prudent and efficient costs over the 2015-20 RCP, both as a result of escalating input costs, as well as the need for additional works to meet demand and customer expectations and to satisfy regulatory obligations and requirements. SA Power Networks simply cannot meet these growing costs by improving efficiency elsewhere in its business. Requiring these increased costs to be met via improved efficiencies, when SA Power

Networks' business is already efficient, also means that there is no scope for SA Power Networks to be rewarded for efficiency gains made over the 2015-20 RCP (i.e. the cost savings from these efficiency gains will be used to meet the increased costs rather than accruing for the shared benefit or SA Power Network and consumers).

8.5 Revised Proposal Summary

As summarised in Table 8.5 the revised operating expenditure forecast, for the provision of SCS for the 2015-20 RCP, is $1,421.9 (June 2015, $ million), excluding debt raising costs and DMIA. This revised forecast has been prepared taking into account consideration of the AER's Preliminary Determination, public submissions on SA Power Networks' Original Proposal and further refinement of our program criteria and forecasting methodologies.

Table 8.5: SA Power Networks SCS operating expenditure costs for the 2015-20 RCP (June 2015, $ million)

	Original Proposal	Preliminary Determination	Revised Proposal	Comment
Adjusted base year	1,199.2	1,195.3	1,195.3	Accept, refer Section 8.6
Rate of change	108.1	26.4	86.6	Sections 8.7-8.10
Step changes	216.8	4.1	140.0	Sections 8.11-8.25
Total (excl debt raising & DMIA)	**1,524.1**	**1,225.8**	**1,421.9**	
Debt raising	27.0	10.1	10.1	Accept, see below
DMIA	3.0	3.0	3.0	Accept, see below
Total (incl debt raising & DMIA)	**1,554.1**	**1,238.9**	**1,435.0**	

SA Power Networks accepts the AER's preliminary decisions with respect to debt raising costs and the DMIA for the 2015-20 RCP. The AER has provided, separate to the operating expenditure allowance, an annual DMIA of $0.6 (June 2015, $ million) to investigate and conduct broad-based and/or peak demand management projects.

We also accept the preliminary decision on the adjusted base year although, as discussed further in Section 8.6 of this chapter, we are concerned at the AER's choice of language in relation to describing SA Power Networks' base year as not 'materially inefficient'. We believe this does not recognise SA Power Networks' clear status as an efficient DNSP and reflects inconsistency in the AER's decision that need to be addressed.

However, SA Power Networks rejects the AER's preliminary decisions with respect to rate of change and step changes, as explained in detail in Sections 8.7 to 8.25 of this chapter.

8.6 Base year

8.6.1 Rule requirements

Clause 6.5.6(c) of the NER provides that the AER must accept the proposed operating expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied that the forecast operating expenditure for the 2015-20 RCP reasonably reflects the operating expenditure criteria, which are:

1) the efficient costs of achieving the operating expenditure objectives;
2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and
3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

In accordance with its Expenditure Forecast Assessment Guideline (**Guideline**), the AER has adopted a base-step-trend approach to determining the allowable operating expenditures for the 2015-20 RCP.

The AER states in the Guideline that:

> *'If actual expenditure in the base year reasonably reflects the opex criteria, we will set base opex equal to actual expenditure for those cost categories forecast using the revealed cost approach'.*[158]

8.6.2 SA Power Networks' Original Proposal

SA Power Networks proposed that the efficient base year be 2013/14 as the operating expenditure in that regulatory year provided an efficient base from which to forecast operating expenditures to fulfil our obligations with respect to SCS during the 2015-20 RCP. This was supported by the consistency of the 2013/14 expenditures with both the prior regulatory year expenditures, the operating expenditure allowances approved by the AER in its 2010 Determination, and our benchmarking analysis, which showed SA Power Networks as the most efficient distributor in the NEM.

SA Power Networks proposed a base year expenditure of $1,199.2 (June 2015, $ million – excluding DMIA) for the 2015-20 RCP after applying adjustments of $34.8 (June 2015, $ million).

8.6.3 AER's Preliminary Determination

In making its Preliminary Determination, the AER accepted our proposed base year operating expenditure as it deemed it to be not materially inefficient, based on its benchmarking analysis. The AER acknowledged that there are valid reasons for increasing operating expenditure and declining productivity over the benchmarked 2006-2013 period, particularly as this was a consistent trend across all DNSPs.

In its Preliminary Determination, the AER reduced SA Power Networks' base year expenditure by $2.0 (June 2015, $ million) primarily for a reduction in the vegetation management pass-through allowance for 2014/15. The AER also made a number of other changes to the base year adjustments resulting in a base year expenditure for the 2015-20 RCP of $1,195.3 (June 2015, $ million) as set out in Table 8.6.

[158] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, page 22.

8.6.4 SA Power Networks' response to AER Preliminary Determination

Whilst we are pleased that SA Power Networks' base year operating expenditure has been deemed efficient, we are disappointed that the AER has then chosen to refer to our base year operating expenditure as 'not materially inefficient'.

SA Power Networks has benchmarked as one of the most efficient distributors in the NEM, and is significantly more efficient than the AER's revised benchmark frontier. Had an allowance for environmental factors been applied, SA Power Networks would clearly be at the efficient frontier. We note, for example, that the AER applies an environmental factor of 23% to ActewAGL, largely for its capitalisation practices. As SA Power Networks expenses most of its network overheads and all of its corporate overheads, we would expect at least a similar allowance to have been applied to SA Power Networks.

In general, we are of the view that the AER has not had due regard to SA Power Networks' position as one of the most efficient DNSPs in the NEM in its Preliminary Determination.

8.6.5 Revised Proposal

Table 8.6 summarises the breakdown of the adjusted 2013/14 base year in a manner that is consistent with the AER's Preliminary Determination.

Table 8.6: SA Power Networks revised SCS adjusted operating expenditure base year for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Base year	245.4	245.4	245.4	245.4	245.4	**1,227.0**
Self insurance	(3.2)	(3.2)	(3.2)	(3.2)	(3.2)	**(16.0)**
Metering reclassification (i)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	**(11.0)**
DMIA (ii)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	**(7.2)**
Provision adjustment	0.5	0.5	0.5	0.5	0.5	**2.5**
Adjusted base year*	**239.1**	**239.1**	**239.1**	**239.1**	**239.1**	**1,195.3**

* Does not add due to rounding

Note: (i) While the AER has appropriately deducted certain metering services expenditure from SCS operating expenditure allowances, due to a reclassification of those services from SCS to alternative control services (ACS) in the 2015-20 RCP, we note later in Chapter 17 of this Revised Proposal that it has failed to include the corresponding expenditure in ACS operating expenditure allowance.

(ii) DMIA has been removed from the operating expenditure base-step-trend calculation and treated as a separate allowance (of $0.6 (June 2015, $ million) p.a.)

8.7 Rate of Change

8.7.1 Rule requirements

Under the base-step-trend methodology for deriving efficient operating expenditure, an 'annual rate of change' is applied to base year costs. The rate of change formula for operating expenditure is:

output growth + real price growth – productivity growth

The rate of change is expected to provide an efficient escalation of base year costs for a proportional increase in operating costs for network growth, real price increases for cost inputs, and to account for expected changes in productivity for the 2015-20 RCP.

8.7.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks proposed an increase in operating expenditure of $108.1 (June 2015, $ million) for rate of change.

8.7.3 AER's Preliminary Determination

In its Preliminary Determination, the AER rejected SA Power Networks' rate of change assumptions and applied a substitute forecast of $26.4 (June 2015, $ million). The key decisions made by the AER contributing to the reduction in the rate of change were as follows:

- rejection of SA Power Networks' output growth measures and substitution with its consultant's, Economic Insights (**EI**), measures and weights to forecasts contained in the Reset RIN data;
- rejection of SA Power Networks' labour price escalation based on Enterprise Agreements (**EA**), and substitution with its consultant's, DAE, forecast of the WPI for the EGWWS industry sector;
- rejection of SA Power Networks' forecasts for real price escalators for contracted services, materials and land; and
- application of a 62%:38% proportional split of labour and non-labour costs, with the labour proportion escalated by DAE's forecast of the EGWWS WPI and zero real cost escalation applied to the non-labour proportion.

The AER also applied zero productivity growth, consistent with our Original Proposal.

8.7.4 SA Power Networks' response to AER Preliminary Determination

We have comprehensively reviewed the AER's Preliminary Determination in relation to the rate of change. We do not accept many of the decisions made by the AER and have obtained additional supporting expert advice in a number of areas. In the following Sections 8.8 to 8.10 of this chapter, we have addressed the concerns raised by the AER and explain why our forecasts should be used.

Overall, SA Power Networks contends that the AER has erred by not providing sufficient allowance for:

- the proportional increase in operating costs to maintain and operate new assets for the spatial increase in network capacity that must be installed to meet customer demand, and which has been accepted as efficient in the AER's capital expenditure allowances; and
- real price increases for labour and contractor costs that SA Power Networks is committed to and/or realistically expects to pay, in the 2015-20 RCP.

Further, the AER has not applied the productivity growth factor determined through its econometric modelling, but has assumed zero per cent productivity growth without providing conclusive evidence to support why it expects productivity growth to not continue to be negative into the 2015-20 RCP.

The AER has therefore effectively applied a significant productivity growth adjustment to SA Power Networks in its Preliminary Determination.

SA Power Networks maintains that the AER, in making its preliminary decision, has not had due regard to:

- section 7A of the NEL, that requires that DNSPs be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control services; and
- the operating (and capital) expenditure criteria in clauses 6.5.6 (and 6.5.7) of the NER, that requires AER to accept a forecast that reflects a realistic expectation of the cost inputs required by an efficient and prudent DNSP to achieve the operating (and capital) expenditure objectives.[159]

8.7.5 Revised Proposal

Our revised forecast of the rate of change to be applied to our operating expenditure forecast is $86.6 (June 2015, $ million), as summarised in Table 8.7 below.

Table 8.7: SCS Rate of Change for the 2015–20 RCP (June 2015, $ million)

	Original Proposal	Preliminary Determination	Revised Proposal	Comment
Output growth	46.7	20.5	36.4	Section 8.8
Real Price growth	61.4	5.9	50.2	Section 8.9
Productivity growth	0.0	0.0	0.0	Accept, refer Section 8.10
Total rate of change	**108.1**	**26.4**	**86.6**	

Our Revised Proposal meets the requirements of the NEL and NER mentioned above through forecasts of output growth and real price escalation that are based on predicted demand and realistic, independently derived forecasts and the application of zero per cent productivity growth, despite current negative growth and the expectation of further cost burdens in the 2015-20 RCP. In summary:

- Our Revised Proposal includes a revised forecast for output growth of $36.4 (June 2015, $ million), largely due to inclusion of distribution transformer and substation capacity growth in lieu of the ratcheted maximum demand measure. This is discussed in detail in Section 8.8;
- We have re-applied our EA-based forecast of labour price growth to operating and capital expenditure forecasts. This is discussed in Section 8.9.3;

[159] Clauses 6.5.6(c) and 6.5.7(c) of the NER.

- We have also applied an average of DAE and BIS Shrapnel's forecast of the EGWWS WPI to the proportion of costs that are labour-based contracted services. This is discussed in Section 8.9.4;
- SA Power Networks accepts the AER's preliminary decision to not apply any real escalation to other non-labour costs, provided that the proportion of non-labour costs is set in accordance with our Revised Proposal; and
- Whilst we have applied zero per cent productivity in our Revised Proposal, consistent with the AER's preliminary decision, we maintain that applying a zero per cent productivity growth is only reasonable when considered holistically, and not implicitly or explicitly factored into other rate of change aspects of the operating expenditure allowance. Further discussion is contained in Section 8.10.

8.8 Output Growth

8.8.1 Rule requirements

Clause 6.5.6(c) of the NER provides that the AER must accept the proposed operating expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied that the forecast operating expenditure for the 2015-20 RCP reasonably reflects the operating expenditure criteria, which are:

1) the efficient costs of achieving the operating expenditure objectives;
2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and
3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

Output growth represents a cost input under the AER's base-step-trend method of assessing operating expenditure.

The Expenditure Forecast Assessment Guideline (**Guideline**) requires that output growth be applied as part of the rate of change formula, and is the forecast annual increase in output.[160]

8.8.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks proposed to apply a similar methodology for output growth to that accepted by the AER in its 2010 Determination. This involved applying output drivers of network growth, customer growth and workforce size to historic data contained in our responses to the Economic Benchmarking (**EB**) and Category Analysis (**CA**) regulatory information notices (**RINs**). Economies of scale were applied to each operating cost group.

SA Power Networks' proposed output growth in its Original Proposal was $46.7 (June 2015, $ million). The percentage impact per year is shown in Table 8.8.

[160] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, page 23.

Table 8.8: Original Proposal - output growth (%)

	2015-16	2016-17	2017-18	2018-19	2019-20
Per cent growth	1.07%	1.05%	1.06%	1.02%	0.98%

8.8.3 AER's Preliminary Determination

The AER rejected our proposed output growth escalation in its Preliminary Determination and applied output growth measures and weightings derived by Economic Insights (**EI**) to forecast data contained in the Reset RIN data. EI's output growth weights and measures are as follows:

Table 8.9: EI output growth weights and measures

Output growth measure	Weighting
Customer numbers	67.6%
Circuit line length	10.7%
Ratcheted maximum demand	21.7%

The output growth applied by the AER in its preliminary decision was $20.5 (June 2015, $ million). The percentage impact per year is shown in Table 8.10.

Table 8.10: Preliminary Determination - output growth (%)

	2015-16	2016-17	2017-18	2018-19	2019-20
Per cent growth	0.57%	0.57%	0.57%	0.57%	0.57%

8.8.4 SA Power Networks' response to AER Preliminary Determination

In its Preliminary Determination the AER stated that 'Output growth' captures the change in expenditure due to changes in the level of outputs delivered, such as increases in the size of the network and the customers serviced by that network. An increase in the quantity of outputs is likely to increase the efficient operating expenditure required to service the outputs. Under the AER's rate of change approach, a proportional change in output results in the same proportional change in expenditure.[161]

SA Power Networks acknowledges that the AER has applied its benchmarking methodology to select output measures and weights to measure output growth, and that they are consistent with the output variables used to measure productivity. These measures are customer numbers, circuit length and ratcheted maximum demand as shown above.

[161] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-46.

We are concerned, however, that the output growth measures do not adequately compensate efficient DNSPs for the maintenance and operation of new assets installed through efficient augmentation of the network.

Each of the measures must provide sufficient allowance to maintain and operate new assets required to meet additional areas of demand. Customer numbers may serve as a proxy for the size of the network required to be operated and maintained, but it is the installation of new assets in terms of additional circuit length and capacity installed that has a direct relationship to operating expenditure through increased network management, cyclic inspection and condition monitoring, and programmed and breakdown maintenance costs.

Efficient augmentation of the network due to spatial demand growth will increase the size of the network, for which output growth is expected to provide a proportional increase in operating expenditure. However, where ratcheted maximum demand at the aggregate level is not forecast to increase (as is the case for SA Power Networks in the 2015-20 RCP) then this factor will not provide sufficient operating expenditure escalation to meet the increased costs of providing SCS. That is, under the existing output growth measures no increase in operating allowances will be provided for the maintenance and operation of the increase in network capacity that must be installed to meet demand and that has been accepted as efficient in the AER’s preliminary decision on capital expenditure allowances.

SA Power Networks considers that the AER’s preliminary decision has not provided a sufficient allowance for SA Power Networks to maintain and operate new assets installed to meet the efficient augmentation of the network in accordance with its regulatory obligations and requirements during the 2015-20 RCP.

8.8.5 Revised Proposal

SA Power Networks accepts the AER’s application of three factors to represent customer growth and network growth, for both line length and capacity installed, and the associated weightings to calculate output growth. However, to address the network capacity growth anomaly described above, we have applied distribution transformer and substation capacity growth in lieu of the ratcheted maximum demand measure to calculate our forecast output growth of $36.4 (June 2015, $ million). Distribution transformer and substation capacity growth has been weighted evenly (at 10.85% each), and based on forecasts contained in the Reset RIN data, which is consistent with the AER’s approach in its Preliminary Determination.

Our revised forecast of output growth better reflects the operating expenditure criteria in that it reflects a realistic expectation of the cost inputs required by an efficient and prudent DNSP to achieve the operating expenditure objectives,[162] by providing for a proportional increase in operating expenditure for the maintenance and operation of additional assets installed to meet customer demand.

SA Power Networks’ revised forecast of output growth for the 2015-20 RCP is $36.4 (June 2015, $ million). The percentage impact per year is shown in Table 8.11.

[162] Clause 6.5.6(c) of the NER.

Table 8.11: Revised Proposal - output growth (%)

	2015-16	2016-17	2017-18	2018-19	2019-20
Per cent growth	1.05%	0.96%	0.94%	1.02%	0.92%

8.9 Real Price Growth

8.9.1 Rule requirements

Clause 6.5.6(c) of the NER provides that the AER must accept the proposed operating expenditure forecast that SA Power Networks includes in its building block proposal if the AER is satisfied that the forecast operating expenditure for the 2015-20 RCP reasonably reflects the operating expenditure criteria, which are:

1) the efficient costs of achieving the operating expenditure objectives;
2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and
3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

Real price growth represents a cost input under the AER's base-step-trend method of assessing operating expenditure.

The Expenditure Forecast Assessment Guideline (**Guideline**) requires that real price growth be applied as part of the rate of change formula, and is the forecast annual increase in the real price of inputs.[163]

8.9.2 Real Price Growth Overview

Real price growth incorporates growth in cost inputs. For SA Power Networks this includes labour, contracted services, materials and land. SA Power Networks' revised real price growth forecast for the 2015-20 RCP is $50.2 (June 2015, $ million) as shown in Table 8.12.

Each of the categories of expenditure in Table 8.12 are discussed separately below.

Table 8.12: Operating Expenditure Real Price Growth (June 2015, $ million)

	Original Proposal	Preliminary Determination	Revised Proposal	Comment
Labour	34.4	5.9	38.7	Section 8.9.3
Contracted services	22.7	0.0	11.5	Section 8.9.4
Non Labour	4.3	0.0	0.0	Section 8.9.4
Total Real Price Growth	**61.4**	**5.9**	**50.2**	

[163] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013*, page 23.

We note that the AER has applied a split of operating expenditure between labour and non-labour that does not reflect a reasonable division in the context of SA Power Networks' operations, as discussed in Section 8.9.4.

- In our Revised Proposal, SA Power Networks has re-applied our EA-based forecast of labour price growth to operating expenditure (refer Section 8.9.3), as this approach represents the real price increases for labour that SA Power Networks is committed to and/or realistically expects to pay in the 2015-20 RCP;
- For labour related contracted services, our Revised Proposal applies an average of DAE and BIS Shrapnel's forecast of the EGWWS WPI to the proportion of costs that are labour-based contracted services (refer Section 8.9.4); and
- SA Power Networks accepts the AER's preliminary decision to not apply any real escalation to other non-labour costs, provided the proportion of non-labour costs is set in accordance with our Revised Proposal (refer Section 8.9.4).

8.9.3 Real Price Growth - Labour

This Section relates to the real escalation of labour costs. Escalation of contracted services costs is included in Section 8.9.4 (Real Price Growth - Non-Labour).

8.9.3.1 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks identified labour as one area of cost that will experience higher than a CPI increase in the 2015-20 RCP.

SA Power Networks engaged Frontier Economics to develop a labour escalation rate that provided a realistic forecast of labour costs for the 2015-20 RCP.

To forecast real labour cost escalation rates, SA Power Networks proposed to use:

- its own Enterprise Bargaining Agreement (**EA**) outcomes for the first two regulatory years of the 2015-20 RCP; and
- an extrapolation of benchmarked EA outcomes from similar businesses based on analysis by Frontier Economics, for the remaining regulatory years of the 2015-20 RCP.

In our Original Proposal, SA Power Networks forecast real price escalation for labour of $34.4 (June 2015, $ million), based on the escalators shown in table 8.13.

Table 8.13: Original Proposal - Forecast Labour Growth (%)

	2015-16	2016-17	2017-18	2018-19	2019-20
Per cent growth	1.66%	1.66%	1.77%	1.77%	1.77%

8.9.3.2 AER's Preliminary Determination

In its Preliminary Determination, the AER was of the view that SA Power Networks' labour cost escalators were not reasonable for the following reasons:

- Either an EGWWS WPI forecast or SA Power Networks' use of benchmark EAs could be reasonable forecasts of the labour price and, in those circumstances; there is no clearly preferable methodology to forecast the labour price;[164]
- The proportion of staff covered by a privately owned DNSP's benchmark EAs does not reflect a significant portion of its in-house labour;[165]
- The benchmark EA wage increases do not represent current market conditions for electricity workers;[166]
- SA Power Networks' labour price growth based on its EA may accurately reflect SA Power Networks' wage increases, but this measure does not take into account the increase in productivity that would be expected; and[167]
- DAE's forecast of the EGWWS industry WPI reflects a more reasonable forecast of the labour price for the rate of change than the forecast proposed by SA Power Networks.[168]

In its Preliminary Determination, the AER substituted its own labour cost escalation rates by adopting the DAE forecast of the EGWWS industry WPI.[169] The AER forecast real price escalation for labour of $5.9 (June 2015, $ million), based on the escalators shown in the table below.

Table 8.14: Preliminary Determination - forecast labour growth (%)

	2015-16	2016-17	2017-18	2018-19	2019-20
Per cent growth	-0.11%	0.40%	0.42%	0.51%	0.56%

8.9.3.3 SA Power Networks' response to AER Preliminary Determination

SA Power Networks does not accept the AER's approach to determining labour cost escalators. The AER's approach does not provide a realistic expectation of the cost inputs SA Power Networks requires to meet the expenditure objectives and therefore does not provide a reasoned basis for SA Power Networks to change its approach to forecasting its labour cost escalators.

For SA Power Networks, labour includes internal labour and labour sourced from a panel of external agencies to supplement its internal labour for increased workloads or absences.

SA Power Networks considers that, contrary to the AER's assertions, our labour escalation is valid and appropriately forecasts the additional costs that SA Power Networks will incur during the 2015-20 RCP. In particular:

- the combination of SA Power Networks' actual EA and the benchmark EA wage increases do represent current market conditions for electricity workers;
- SA Power Networks' labour escalations cover almost all of our employees (around 95%);
- the use of the benchmark EAs is a more preferable methodology than the EGWWS WPI and provides a more reasonable and transparent forecast for the labour price rate of change; and
- productivity adjustments have been taken into account in assessing labour escalations.

---

[164] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-50.
[165] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-51.
[166] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-52.
[167] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-54.
[168] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-50.
[169] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-56.

In addition, SA Power Networks has engaged expert consultants to review the decisions made by the AER in relation to labour price escalation in its Preliminary Determination. Their findings are discussed below and are contained in the following attachments to our Revised Proposal:

- Attachment H.1 – Frontier Economics, '*Review of AER's Preliminary Decision on Labour Escalation Rates*', June 2015; and
- Attachment H.2– NERA Economic Consulting (**NERA**), '*Expert Report on the Allowed Rate of Change in SA Power Networks' Expenditure due to Expected Inflation in Labour Costs*', June 2015.

The key considerations demonstrating that the AER has erred in rejecting SA Power Networks' labour cost escalators are discussed in detail below.

The combination of SA Power Networks' actual EA and the benchmark EA wage increases do represent current market conditions for electricity workers in South Australia

SA Power Networks' current EA expires on 31 December 2016. The final salary increase is effective from the first pay period commencing on or after 1 July 2016[170] and therefore applies for the first two regulatory years of the 2015-20 RCP. SA Power Networks is bound by the terms and conditions of our current EA, including the payment of salary and wage increases prescribed in the EA.

The labour cost escalators derived from SA Power Networks' EA are reflective of current market conditions for electricity workers in South Australia. The EA was negotiated at arm's length and in a commercial manner, and resulted in an outcome reflecting the efficient and realistic costs SA Power Networks expects to prudently incur in the provision of network services.

During this bargaining process, SA Power Networks achieved the most efficient pay outcomes by:[171]

- balancing the need to secure the lowest possible input costs; whilst
- ensuring that it could pay its workers sufficiently to retain their high skills and maintain productivity; and
- minimising the threat of costly and disruptive industrial action in our essential service industry.

The relative bargaining strength of employees and unions, and the nature of the work and industry environment, are key influencers of the outcomes of the negotiation of enterprise agreements.

The electricity industry is highly unionised and during the bargaining process unions are able to implement disruptive industrial action under the provisions of the *Fair Work Act 2009* (Cth) in their endeavours to seek the most favourable outcomes for their members. In relation to negotiations with SA Power Networks, the relevant unions operate as a single bargaining unit in pursuit of a collective agreement and therefore represent almost all sectors of the business.

SA Power Networks' obligation to comply with all regulatory obligations or requirements and to maintain the reliability, safety and security of the distribution system[172] must also be considered in negotiating EAs.

---

[170] SA Power Networks, *Utilities Management Pty Ltd Enterprise Agreement 2014*, May 2014, page 3. Note Utilities Management Pty Ltd is the legal entity that employees SA Power Networks' employees.
[171] SA Power Networks*, Regulatory Proposal 2015-20, Attachment 20.2 – Frontier Economics, Forecasting labour cost escalation rates using EBA outcomes*: A report prepared for SA Power Networks, August 2014, page 24.
[172] Clauses 6.5.6(a) and 6.5.7(a) of the NER.

Further evidence outlining the nature and extent of the EA bargaining process and demonstrating that SA Power Networks' EA is reflective of current market conditions, is contained in Frontier Economics report provided as Attachment 20.2 to our Original Proposal.

As concluded by Frontier Economics, SA Power Networks' EA is in line with the average EA outcomes of a set of comparators.[173] In fact, annualised wage increases for collective agreements for the EGWWS industry sector have averaged 4.4% over the 2006 to 2014 period,[174] which is consistent with SA Power Networks' current EA nominal labour escalation rates.

Complying with the EA is mandatory for SA Power Networks. It amounts to a 'regulatory obligation or requirement' under section 2D of the NEL. SA Power Networks' EA is an instrument issued under an Act of a participating jurisdiction that materially affects the provision, by SA Power Networks, of electricity network services that are the subject of a distribution determination, for the following reasons:

- The EA is an instrument certified by the Fair Work Commission under the *Fair Work Act 2009* (Cth);
- Section 50 of that Act requires SA Power Networks to comply with the terms and conditions in the EA;
- As found by the Full Court of the Federal Court in *Australian Industry Group v Fair Work Australia* [2012] FCAFC 108, an EA has statutory force and, as a statutory instrument, it has more formality and greater consequence than any contract arrangement or understanding could have;[175]
- The *Fair Work Act 2009* (Cth) is an Act of the Commonwealth which is, by virtue of section 6 of the *Australian Energy Market Act 2004* (Cth), a 'participating jurisdiction' under the NEL; and
- Labour costs arising under the EA are a material cost input affecting the provision of electricity network services by SA Power Networks.

This means that expenditure required to comply with SA Power Networks' EA, including the labour costs prescribed by it, satisfies the expenditure objectives in clauses 6.5.6(a)(2) and 6.5.7(a)(2) of the NER in that it is expenditure required in order to comply with all applicable regulatory obligations or requirements associated with the provision of SCS.

The use of EA outcomes to inform labour cost escalation rates is also consistent with the 2010 Australian Competition Tribunal (**Tribunal**) decision on the AER's approach to Ergon's labour cost escalators[176] and recent decisions by the AER.[177] The Tribunal's decision in Ergon confirms that the AER must at the very least consider whether, given the circumstances in which it was negotiated, the rates set out in SA Power Networks' EA reasonably reflect the relevant labour cost inputs that will be faced by SA Power Networks in the first two years of the 2015-20 RCP. SA Power Networks has already submitted expert reports to the AER which support the conclusion that they do.[178]

SA Power Networks' proposed labour cost escalators, as a key component of its total forecast expenditure for the 2015-20 RCP, meet the expenditure criteria in clauses 6.5.6(c) and 6.5.7(c) of the NER. That is, SA Power Networks' proposed labour cost escalators reasonably reflect the efficient costs

---

[173] SA Power Networks, *Regulatory Proposal 2015-20*, Attachment 20.2 – *Frontier Economics, Forecasting labour cost escalation rates using EBA outcomes*: A report prepared for SA Power Networks, Appendix B, August 2014.
[174] BIS Shrapnel, *Utilities Sector Wage Forecasts to 2019/20 – Australia and South Australia*, May 2015, page 25.
[175] Australian Industry Group v Fair Work Australia [2012] FCAFC 108, [69] – [73].
[176] Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11 (24 December 2010).
[177] AER, *Final Determination: SP AusNet Transmission determination 2014-15 to 2016-17*, January 2014.
[178] See SA Power Networks, *Regulatory Proposal 2015-20*, Attachment 20.2 – *Frontier Economics, Forecasting labour cost escalation rates using EBA outcomes*: A report prepared for SA Power Networks, August 2014.

that a prudent operator would incur in complying with an EA and a realistic expectation of the cost inputs required to do so.

The AER's assumption that the benchmark EA wage increases do not represent current market conditions is based, in part, on its analysis of a material difference between Frontier Economics' benchmark comparator sample and the EGWWS WPI for 2013/14. The AER:

> *'[does] not consider wage increases in other EGWWS industries are likely to be sufficiently different to the electricity industry to fully account for the 1.5 per cent difference'.[179] The AER 'consider[s] it is more likely that the private sector EAs in Frontier Economics' comparator group is not representative of wage increases in the electricity sector'.[180]*

The AER's analysis is misleading; it is not making a like-with-like comparison. The AER appears to be comparing Frontier Economics' forecasts based on privately-owned DNSP's EAs (the comparator group) of 4.5% for 2013/14 to the national EGWWS WPI, which was 3.2% for 2013/14[181] (rather than the 3.0% quoted in the AER's Preliminary Determination).[182]

Frontier Economics' forecast of EA rates for all electricity networks for 2013/14 is 3.6%,[183] which is much more comparable with the national EGWWS WPI of 3.2%.

Frontier Economics concludes that when expressed on a more comparable basis, the gap between EA rates and the EGWWS WPI is much narrower than suggested by the AER. Therefore it is very plausible that wage increases in other EGWWS industries, and also in publicly-owned DNSP EAs, are sufficiently different to account for the observed gap between the comparator group EAs and the EGWWS WPI.[184]

Frontier Economics further notes that there has been a material divergence in EA rates of privately-owned and publicly-owned NSPs in recent years, which is likely to have arisen, in part, from the effect of several State Governments introducing caps on public sector workers[185] during a period of fiscal strain.

Frontier Economics provides additional commentary on this subject in its report at Attachment 20.2 to our Original Proposal, ie:[186]

- In recent years, almost all State Governments (eg New South Wales, Victoria, Queensland, South Australia and Western Australia) have introduced caps on public sector pay increases, motivated by State level fiscal pressures;
- It is very likely that these restrictions will have imposed constraints on publicly owned networks when negotiating EAs; and
- In Frontier Economics' view, during times of tight fiscal conditions, faced with the trade-off between caps on pay increases or more widespread public sector redundancies, it is likely that unions negotiating with public sector employees would accept lower pay increases.

---

[179] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-52.
[180] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-52.
[181] ABS, *Index 6345.0 Wages Price Index, March 2015, or DAE, Forecast growth in labour costs in NEM regions of Australi*a, 23 February 2015, page 11.
[182] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-52.
[183] Frontier Economics, *Review of AER's Preliminary Decision on Labour Escalation Rates*, May 2015, page 11.
[184] Frontier Economics, *Review of AER's Preliminary Decision on Labour Escalation Rates*, May 2015, page 11..
[185] Frontier Economics, *Review of AER's Preliminary Decision on Labour Escalation Rate*s, May 2015, page 11.
[186] SA Power Networks, *Regulatory Proposal 2015-20*, Attachment 20.2 – Frontier Economics, *Forecasting labour cost escalation rates using EBA outcomes*: A report prepared for SA Power Networks, August 2014, page 34-35.

In assessing whether the comparator group EAs do reflect market conditions, it must be noted that wage growth rates may be driven by a wide range of factors. As described previously, the relative bargaining strength of employees and unions and the nature of the work and industry environment are key influencers of the outcomes of the negotiation of EAs. Retention of key skills and the availability of resources are other contributing factors.

The skills required in the electricity distribution industry are highly specialised and cannot easily be sourced or transferred from other industries. Electricity assets are highly complex and powerline workers in particular require specific training to operate on network assets. Further, electrical work requires a high level of industry-specific health and safety training which is not provided in other industries.

The electricity distribution industry must therefore continue to invest in developing the skills of its electricity workers and must offer competitive employment conditions to attract and retain quality resources. High employee turnover will increase long run costs, and can also have a negative effect on employee morale and consequently productivity as well as safety.

Availability of resources is also a contributing factor to labour price growth. In its Preliminary Determination the AER stated that

> *'[t]here is no evidence to suggest that there is a supply and demand imbalance in electricity labour'.*[187]

Frontier Economics queries what evidence the AER has considered in this regard, but notes the following three key assertions made by the AER's adviser, DAE, in its February 2015 report:

- that the 'utilities' (in reference to the EGWWS Division) and 'resources' (ie mining) sectors compete for workers;
- that the recent downturn in the resources sector has released significant quantities of labour, which has weakened the degree of competition for workers between the utilities and resources sectors – and this trend will continue over the outlook period; and
- as a result, wage gains in the utilities sector are expected to slow.

This relates specifically to DAE's claim that:

> *'In particular, competition for workers with some of the same skills as those in the utilities sector is now waning:*
>
> *The competition for utilities sector workers from the resources sector has dissipated and will decrease further over the outlook period. In February 2015, on the back of plummeting oil prices, global resources services provider Halliburton announced an 8% cut to its global workforce joining Baker Hughes and Schlumberger in similar moves. Australia's resources sector is following global cost reductions and the subsequent reduced competition for workers will slow wage gains in the utilities sector.'*[188]

Frontier Economics considers that there are a number of problems with DAE's claims:[189]

- DAE provides no evidence that labour in the utilities sector is substitutable;

[187] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-54.
[188] DAE, *Forecast growth in labour costs in NEM regions of Australia*, 23 February 2015, page 3.
[189] Frontier Economics, *Review of AER's Preliminary Decision on Labour Escalation Rates*, May 2015, page 16.

- even if the occupations within the sectors were closely substitutable, labour is not generally mobile; and
- DAE refers vaguely to the 'utilities sector'; generalisations about labour requirements for this are inappropriate as there is little overlap between the occupations within DNSPs and non-electricity network members of the EGWWS[190] (ie it is more appropriate to consider substitutability between DNSPs and the mining sector).

Frontier Economics shows in its report that there is also low overlap in occupations for the electricity distribution class of the utilities sector and mining (ie resources) sector[191] and observes the following:[192]

- there is no reason to believe that labour being released from the mining industry, with the exception of electricians, is more likely to be absorbed by DNSPs that any employers in any other industry;
- workers in general roles are less likely to be mobile than specialist workers required by DNSPs, as the premium that specialised labour can command may be sufficient to offset the disamenity associated with relocating to a new state;
- workers in general occupations may be able to move relatively easily into similar roles in other industries, and as such are more likely to search for roles in their home state than incur costs to relocate to South Australia; and
- the specialist occupations required by DNSPs are roles that require significant investment in training and would mean some lag between the release of general labour from the mining industry and the absorption of those workers as specialist labour by DNSPs.

Frontier Economics are of the opinion that the claims made by DAE are weak. Frontier Economics conclude that:

> *'In our view, labour is not as substitutable between these sectors as DAE and the AER suggest. This, in turn, could mean that, particularly in the short-run, labour costs could rise more quickly than productivity if there are demand-supply imbalances in the electricity networks industry.'*[193]

In support of this, a study was undertaken by SA Power Networks in 2012, which identified shortages and difficulties in recruiting for the following occupations:

- substation engineers;
- protection engineers;
- secondary designers;
- substation maintenance planners;
- technical officers;
- electrical engineers (with suitable experience);
- project managers (with expertise in emerging technologies such as smart-grid);
- telecoms engineers;
- diesel mechanics; and

---

[190] Ibid, section 2.1, page 5-7.
[191] Ibid, page 18.
[192] Ibid, page 18-19
[193] Frontier Economics, *Review of AER's Preliminary Decision on Labour Escalation Rates*, May 2015, page 19.

- trade skilled workers (**TSWs** - both electrical and power-line, particularly with specialist knowledge such as fault identification and corrective skills, telecoms, commissioning etc).

Although conducted almost three years ago, the key findings remain valid. Further details are contained in Attachment H.3 (*Skill shortages in SA Power Networks*). The report includes recent statistics and observations in relation to South Australia's small population, low population growth and net deficit in state migration.[194] Key findings of the report include:

- South Australia has a limited resource pool for many of the occupations and skills in short supply;
- a large proportion of applicants are unsuitable as they lack appropriate skills, qualifications, knowledge or specific industry experience;
- interstate applicants deem South Australian remuneration to be too low for some positions; and
- a high number of SA Power Networks' employees fall into a specialist occupation category, requiring specialised skills and extensive training.

Similar to Frontier Economics' analysis, this report also considers the availability of resources from a downturn in the mining industry and concludes that[195]:

- more than 86% of mining-related employment occurs in the 'mining states' of Western Australia, Queensland and New South Wales;
- workers least qualified for a career move to SA Power Networks are the most likely to face job losses in the mining industry;
- only eight per cent of mining workers are employed as electricians, and fewer still in each of the various engineering specialties;
- employment in mining has been declining for some time, but there has been no increase in applications for SA Power Networks' traditionally 'hard to fill' occupations in this time; and
- many of the skills in the mining industry are equally transferable to the construction industry, for which worker growth is forecast to be more than three times forecast losses in the mining industry to 2019.

From the above, we conclude that supply and demand imbalances may also be a contributor to EA labour price increases.

In conjunction with the need to enhance and retain specific skills, high unionisation in the electricity industry, the nature of the work environment as an essential service, and that comparator group EA rates are consistent and stable, we strongly contend that benchmark EA wage increases are highly representative of current market conditions for electricity distribution workers.

SA Power Networks' labour escalations cover almost all of our employees (around 95%)

In its Preliminary Determination, the AER noted that a key consideration in determining whether an EA is a reasonable measure of labour price growth, is whether the proportion of staff covered by the EA is representative of the overall electricity workers of the relevant DNSP. In SA Power Networks' case, all internal employees whose classification is covered by a salaries or wages grade structure are bound by the current EA.[196] This represents around **95% of our employees** and is therefore exceedingly representative of the employees of SA Power Networks.

---

[194] ABS, *Catalogue No. 3101.Australian Demographic Statistics*, September 2014.
[195] Attachment H.3, *Skill shortages in SA Power Networks*, June 2015, pages 7-8.
[196] SA Power Networks, *Utilities Management Pty Ltd Enterprise Agreement 2014*, page 2.

Supplementary labour resources are also effectively bound by the EA through a contractor parity clause that requires the payment of EA rates of pay, including allowances. Where contractor labour resources are utilised to supplement SA Power Networks' internal labour due to absences or increases in workload, the contractor must pay its workers, '*as a minimum, the total Utilities Management rate comprised of the Enterprise Agreement rate of pay … and regularly paid allowances for the classifications appropriate to the duties being performed'*.[197]

In its Preliminary Determination, the AER asserted that the proportion of staff covered by a privately owned DNSP's benchmark EA does not reflect a significant portion of its in-house labour. SA Power Networks refutes this assertion as it can be clearly shown that SA Power Networks' EA is highly representative of its labour resource, covering approximately 95% of internal employees and providing wage parity for its supplementary contract labour. This was also highlighted by DAE in its report to the AER in support of the Preliminary Determination for the Queensland DNSPs.[198]

Additionally, analysis of data provided by the Australian Bureau of Statistics (**ABS**) and Department of Employment shows that nearly 68% of employees in the EGWWS sector are covered by collective agreements, a much higher proportion than most other industries.[199] It is highly likely therefore that EAs reflect coverage of a high proportion of electricity distribution workers.

Nevertheless, EAs should also serve as a good proxy for other workers in the electricity distribution industry. Section 346 of the *Fair Work Act 2009* (Cth) prohibits an employer from discriminating against an employee on the basis of participation (or non-participation) in trade unions. Therefore if employees that are not covered by EAs wish to be included, they could elect to opt in to an EA (assuming that their classification is encompassed in the EA).

We contend therefore that the conclusion by the AER that EAs do not reflect a significant portion of SA Power Networks' in-house labour is unreasonable.

The use of the benchmark EAs is a more preferable methodology than the EGWWS WPI and provides a more reasonable and transparent forecast for the labour price rate of change

When selecting a measure for forecasting labour escalation, consideration must be given to whether the expenditure reasonably reflects the operating (and capital) expenditure criteria, which include:

1) the efficient costs of achieving the operating (or capital) objectives; and
2) the costs that a prudent operator would require to achieve the operating (or capital) expenditure objectives; and
3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating (or capital) expenditure objectives.[200]

In its Preliminary Determination, the AER notes that '*[t]he choice of labour price measure should reflect the annual change in labour price for electricity distribution workers'*.[201] In relation to the use of EAs or the EGWWS WPI to forecast labour price, the AER also notes that '*there is no clearly preferable methodology to forecast the labour price'*.[202]

---

[197] SA Power Networks, *Utilities Management Pty Ltd Enterprise Agreement 2014*, page 58. Note Utilities Management Pty Ltd is the legal entity that employees SA Power Networks' employees.

[198] DAE, *Queensland Distribution Network Service Providers – Opex Performance Analysis*, Report prepared for the AER, April 2015, page 31.

[199] BIS Shrapnel, *Utilities Sector Wage Forecasts to 2019/20 – Australia and South Australia*, derived from ABS data, May 2015, page 19.

[200] Clauses 6.5.6(c) and 6.5.7(c) of the NER.

[201] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-2*0, April 2015, page 7-51.

[202] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-50.

The AER, in its preliminary decision to apply the EGWWS WPI to forecast labour price, has failed to recognise the limitations of the EGWWS WPI based forecasts and the advantages of the EA-based approach. To reiterate:

- the EGWWS WPI includes workers from other utilities and other subsets of the electricity industry which have different skill requirements and is therefore not reflective of the wage price growth in the electricity distribution industry;
- EGWWS data is not available for South Australia and must be imputed from national data;
- consultant forecasts of EGWWS WPI forecasts vary widely, highlighting the volatility of measurement techniques, and have not proven to be accurate or reliable;
- EA growth rates are transparent and replicable and can be calculated from publicly available data;
- EA rates have been relatively stable over time and provide direct representation of labour wages growth rates in the electricity distribution business; and
- EA rates provide the most realistic expectation of the cost inputs required to achieve the operating (and capital) expenditure objectives.

EAs clearly reflect the annual change in labour price for electricity distribution workers at SA Power Networks and the application of EAs for labour price escalation is clearly preferable to the use of the EGWWS WPI.

Further, DAE’s forecasts lack both transparency and consistency and should not be favoured by the AER over EA-based forecasts.

With respect to transparency, DAE’s report explains that its wage forecasts come from its proprietary labour cost model, linked to its macroeconomic model. Macroeconomic modelling of this sort entails numerous assumptions and methodological choices, which DAE has not divulged.

SA Power Networks sought additional information from the AER on DAE’s forecasting model. DAE provided a high level explanation of its data and models, but not in sufficient detail to enable detailed analysis. DAE declined to provide further information on the grounds that the information was commercially sensitive, and in the case of some of the data, obtained by subscription from the ABS.[203] To enable a reasoned analysis by a researcher outside of DAE, details would be required to specify:

- the numerical formula by which the historical series of WPI for EGWWS in South Australia was constructed; and
- the precise forecasting method or econometric model used to forecast future WPI growth in EGWWS in South Australia based on the imputed historical series.

So, in choosing DAE’s index as the basis for its labour price growth forecast, the AER cannot transparently demonstrate that it is providing DNSPs with *’a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control services’*, consistent with the requirement specified in section 7A of the NEL. This also fails the AER’s own principles of transparency as described in its Guideline, *’because it is not possible to assess the results in the context of the underlying assumptions.’*[204]

[203] AER email to SA Power Networks dated 3 June 2015.

[204] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, page 16.

The AER, however,

> *'consider[s] the EGWWS WPI forecast by DAE to be a reasonable forecast of the labour price which takes into account current market conditions.'*[205]

SA Power Networks challenges this as there is no practical way to compare DAE's forecasts to outturns; which is the usual way to judge the soundness of particular forecasts or forecasting methods. By contrast, EA-based forecasts can be compared readily to outturns.

DAE acknowledges that the historical South Australian EGWWS WPI is imputed and that there is no guarantee that the imputed values would actually match what the ABS data would show, were it to be released.[206]

We are also concerned that DAE's forecast of the EGWWS WPI is neither consistent nor reasonable. Frontier Economics notes that DAE has forecast the EGWWS WPI to fall to a level that is unprecedentedly low compared to EA rates.[207] DAE has not offered any valid explanation of this and possible explanations are not supported by available evidence. For example:

- there is no evidence of a sudden acceleration in labour productivity growth in the industry;
- there is no evidence that the rates of pay increase for workers not covered by EAs are lagging behind rates of pay increase for workers that are covered by EAs; and
- there is no indication of a change in market conditions for workers in the EGWWS industry that is reflected in the WPI but not yet being fully reflected in EA outcomes.

Frontier Economics also notes significant changes made by DAE to its EGWWS WPI forecasts between 2013 and 2015.[208] In its 2015 report, DAE has concluded that actual rates of increase in WPI in 2012/13 and 2013/14 were about one percentage point higher than it had forecast in its 2013 report. In its 2015 report DAE has also, notwithstanding the above corrections and without explanation, made significant downward revisions to its EGWWS WPI for South Australia in 2015/16 and 2016/17.

The lack of transparency and reasonableness of DAE's labour price forecasts provides further support for the application of EA-based forecasts by the AER for real labour price increases.

Productivity adjustments have been taken into account in assessing labour escalations

In its Preliminary Determination, the AER '*consider[s] that SA Power Networks EA wage increases …. are only efficient if they are to compensate for labour productivity gains*.'[209] The AER argues that the labour forecasts in our Original Proposal are inefficient because SA Power Networks has not forecast any productivity growth.

SA Power Networks strongly disagrees with the AER's rationale that labour price growth reflected in EAs must be offset by productivity gains in order to be efficient. The AER's rationale relies on a hypothetical relationship between productivity and labour price growth, which must hold at the industry level (eg EGWWS in this context) if it is to support the AER's position. SA Power Networks can demonstrate through empirical analysis that the relationship between productivity and labour price growth at the EGWWS industry level does not hold as explained below.

---

[205] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-55.
[206] DAE, *Forecast growth in labour costs in NEM regions of Australia*, 23 February 2015, Appendix A, page 100-101.
[207] Frontier Economics, *Review of AER's Preliminary Decision on Labour Escalation Rates*, May 2015, page viii.
[208] Frontier Economics, *Review of AER's Preliminary Decision on Labour Escalation Rates,* May 2015, page viii-ix.
[209] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-54.

The AER:

> *'consider[s] that zero productivity in conjunction with SA Power Networks' labour forecast is not likely to lead to an estimate consistent with the opex criteria. This is because over the long term labour price growth adjusted for labour productivity is equal to the change in CPI'.*[210]

To support its views, the AER states that

> *'Professor Borland demonstrates this in analysis that shows that, on average from 1997-98 to 2009-10, CPI plus labour productivity matched the average weekly ordinary time earnings (AWOTE)'.*[211]

The Frontier Economics report at Attachment H.1 is co-authored by Professor Borland, and concludes that it is not valid for the AER to apply that evidence in support of the arguments it seeks to make.[212] Frontier Economics' report states that '*[d]oing so involves a misunderstanding of the purpose for which Professor Borland presented the evidence; and wrongly seeks to draw industry-level inferences from aggregate-level data*.'[213]

The relationship between AWOTE, CPI and labour productivity that Professor Borland described in his previous report held at the aggregate, economy-wide level. However, it is not necessarily the case that the same relationship holds at the (lower) industry-level and can be shown to not hold in the EGWWS industry. The AER has incorrectly relied on this assumption.

To demonstrate this Professor Borland has made the same comparison between AWOTE, CPI and labour productivity based on data to the end of 2014.[214] This comparison is set out in Table 8.15 below.

Table 8.15: Rates of Growth, December 1997 to December 2014 (%)

	All	EGWWS
WPI	3.5%	3.8%
AWOTE	4.4%	4.4%
Labour productivity	1.6%	-2.3%
CPI	2.8%	2.8%

Source: ABS, Professor J Borland's calculations

Table 8.15 shows that for the EGWWS industry:

- average productivity has been negative over the period considered (from 1997 to 2014); and
- the sum of labour productivity and CPI does not equal AWOTE.

---

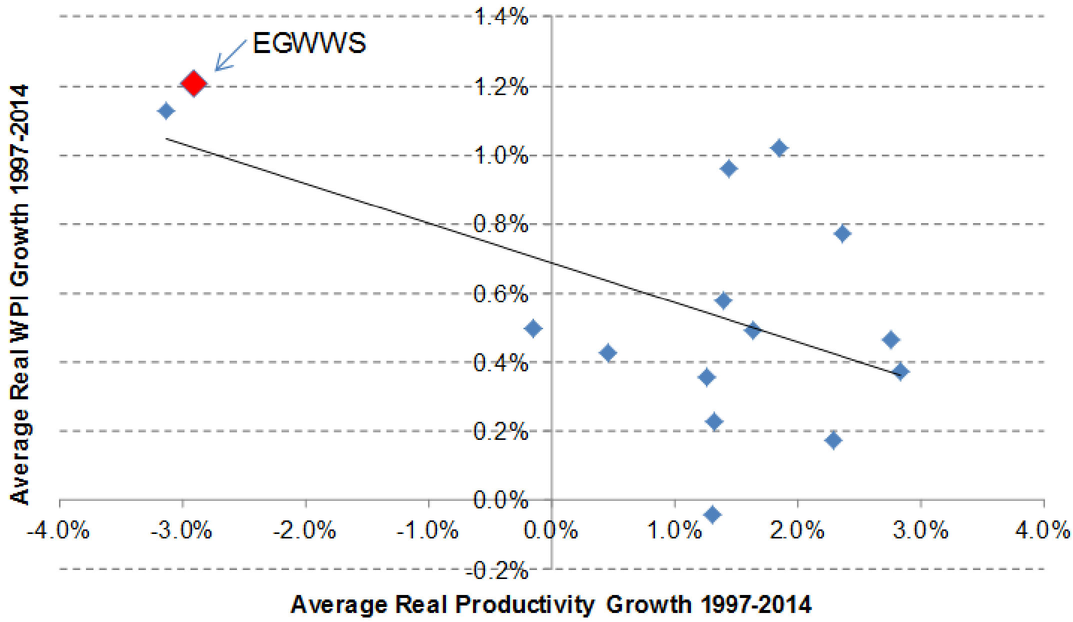
[210] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-54.
[211] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-54..
[212] Frontier Economics, *Review of AER's Preliminary Decision on Labour Escalation Rates,* May 2015, page 13-14.
[213] Frontier Economics, *Review of AER's Preliminary Decision on Labour Escalation Rates*, May 2015, page 14.
[214] Frontier Economics, *Review of AER's Preliminary Decision on labour Escalation Rates*, May 2015, page 15.

Professor Borland concludes that

> *'[t]his analysis demonstrates empirically that it is not necessary that a difference in EBA and WPI outcomes in the EGWWS industry would be explained by positive productivity growth at SA Power Networks.'*[215]

NERA has separately analysed long-term average growth rates in wages and productivity across a range of industries, to arrive at outcomes similar to those from Professor Borland's analyses, as shown in Figure 8.1 below. (Note, in Figure 8.1, the EGWWS industry data point is identified in red).[216]

Figure 8.1: Long-term relationship between productivity and wage growth



Source: ABS, NERA analysis

From its analysis, NERA observes no positive correlation between labour productivity and wages growth at the industry level.

NERA concludes that:

> *'In short, industry-level wage growth rates are driven by a wide range of other factors. Even in the long-run there is no reason to expect that wage growth in a particular industry should be strongly correlated with productivity growth in that industry. Hence, the AER's suggestion that forecasting higher growth in SA Power Networks' labour costs than DAE has projected would be inconsistent with a zero productivity improvement is neither consistent with economic theory nor empirical evidence'.*[217]

[215] Frontier Economics, *Review of AER's Preliminary Decision on labour Escalation Rates*, May 2015, page 15.
[216] NERA, Attachment 8.2, *Expert Report on the Allowed Rate of Change in SA Power Networks' Operating Expenditure due to Expected Inflation in Labour Costs,* May 2015, page 14.
[217] NERA, Attachment 8.2, *Expert Report on the Allowed Rate of Change in SA Power Networks' Operating Expenditure due to Expected Inflation in Labour Costs,* May 2015, page 14.

Further, NERA observes that:

> *'in fact, the AER's proposed determination of zero productivity growth in electricity distribution industry may exaggerate the potential for future productivity improvement, given the long-term trend of reductions in productivity in the sector.'*[218]

The evidence categorically shows that the AER's assertion that EA wages increases are only efficient if they compensate for labour productivity gains is not valid.

SA Power Networks is also concerned that the AER's Guideline and its preliminary decision are ambiguous and inconsistent in the treatment of labour productivity.

The Explanatory Statement to the Guideline states that the AER:

> *'intend[s] to develop a single productivity forecast through econometric modelling of the opex cost function', and that '[a]pplying this single productivity forecast helps avoid the risk of double counting productivity growth.'*[219]

Similarly, in its Preliminary Determination in relation to productivity growth, the AER states that:

> *'[s]ince we take both outputs and inputs into account, our productivity measure accounts for labour productivity and economies of scale.'*[220]

The above statements are contradictory to the AER's assertion that:

> *'SA Power Networks EA wage increases … are only efficient if they are to compensate labour productivity gains'.*[221]

The AER's econometric analysis has shown that modelled productivity growth across the electricity distribution industry, and for SA Power Networks, is negative, but it has chosen to apply zero productivity growth in its Preliminary Determination.

We are concerned therefore that had the AER's econometric modelling produced a neutral or positive productivity growth outcome, it would have applied this as well as extracting further labour productivity growth through an aggressive labour forecast measure (ie DAE's EGWWS WPI). This is not consistent with the expenditure objective of providing for a realistic expectation of cost inputs, nor the Guideline's stated intent not to double-count productivity gains.

The AER also argues that the need for consistency demands that the same labour cost index be used when forecasting price growth and when estimating the rate of productivity growth[222]. However:

- the AER has derived MTFP estimates of productivity using the WPI and found the estimates to be negative; and
- it has then set these estimates aside and assumed a rate of productivity of zero.

---

[218] NERA, Attachment 8.2, *Expert Report on the Allowed Rate of Change in SA Power Networks' Operating Expenditure due to Expected Inflation in Labour Costs*, May 2015, page 15.
[219] AER, *Explanatory Statement to Expenditure Forecast Assessment Guideline*, page 66.
[220] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-47.
[221] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20,* April 2015, page 7-54.
[222] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20,* April 2015, page 7-54.

It therefore cannot be said that the productivity estimate the AER actually uses is consistent with a WPI-based forecast of labour cost escalation rates. The AER is arguing for a level of consistency and precision that is not reflected in its own analysis.

8.9.3.4 Revised Proposal

In our Revised Proposal, SA Power Networks has applied its EA-based forecast of labour price growth to both its operating and capital expenditures.

The labour cost escalators included in this Revised Proposal for the first two regulatory years of the 2015-20 RCP are based on SA Power Networks' current EA and represent the actual rate at which SA Power Networks' real labour costs will increase in those regulatory years.

The labour cost escalators included in this Revised Proposal for the remaining three regulatory years of the 2015-20 RCP following the expiry of SA Power Networks' EA, are based on an extrapolation of benchmarked EA outcomes from similar businesses based on analysis from Frontier Economics.

For the reasons set out above, and as set out in our Original Proposal, this approach is reflective of current market conditions for workers in the electricity industry, with historical EAs of privately owned DNSPs across the NEM being quite stable over time.[223] This approach results in an outcome reflecting the efficient and realistic costs SA Power Networks expects to prudently incur in the provision of network services.

The use of an average of comparator group EAs in forecasting labour escalation, as well as the application of the Efficiency Benefit Sharing Scheme (**EBSS**), will ensure that SA Power Networks is incentivised to continue to achieve the most efficient EA rates over time.

The use of EA-based forecasts also improves upon the AER's use of EGWWS WPI because:

- the approach is highly reflective of the true labour escalation rates of electricity DNSPs, and is not clouded by the inclusion of other non-representative utilities (eg water, waste water) or subsets of the electricity industry that have different skill sets to electricity distribution (eg generation, retail) in the EGWWS industry sector;
- actual EA data is readily available to the AER and stakeholders, who can then assess the validity and accuracy of the approach (particularly given that data has been recently provided to the AER as part of the EB RIN process);
- when applied with SA Power Networks' EA for the first two regulatory years of the 2015-20 RCP, the approach is unlikely to suffer from the discontinuity caused by using two different methodologies; and
- the approach is simple and transparent.

SA Power Networks' revised forecast of real labour price growth for the 2015-20 RCP is $38.7 (June 2015, $ million), as set out in Table 8.12 below.

Forecast real growth rates have been amended in this Revised Proposal to reflect the change in the forecast CPI. This has been reduced from 2.55% per annum to 2.06% per annum in line with latest forecasts, as explained in Chapter 13 (Weighted Average Cost of Capital) of this Revised Proposal. As the EA is based on nominal rates, this has consequently impacted real escalation rates, as set out in Table 8.16 below.

[223] SA Power Networks, *Regulatory Proposal, 2015-20*, Attachment 20.2 – Frontier Economics, *Forecasting labour cost escalation rates using EBA outcomes*: A report prepared for SA Power Networks, August 2014, page 38.

Table 8.16: Forecast labour escalation using EA (%)

	2015-16	2016-17	2017-18	2018-19	2019-20
Nominal %	4.25%	4.25%	4.37%	4.37%	4.37%
Forecast CPI %	2.06%	2.06%	2.06%	2.06%	2.06%
Real %	2.15%	2.15%	2.26%	2.26%	2.26%

Note: the real labour escalation percentage is calculated as the nominal percentage plus one, divided by the CPI percentage plus one, minus one (ie 1.0425/1.0206 - 1).

8.9.4 Real Price Growth - Non-Labour

8.9.4.1 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks proposed the following real escalation of non-labour costs set out in Table 8.17.

Table 8.17: Original Proposal – proposed non-labour escalation [224]

Expenditure category	Cost (%)	Forecast Escalation (June 2015, $million)
Contract services	54.1%	22.7
Materials	0.7%	0.1
Land	1.5%	4.2

Contract services escalation was based on a forecast of the South Australian construction sector WPI provided by BIS Shrapnel. The materials escalation was based on independent forecasts and methodology provided by Competition Economists Group and Jacobs, whilst land escalation was forecast by Maloney Field Services.

8.9.4.2 AER's Preliminary Determination

In its Preliminary Determination, the AER accepted our forecast of the construction sector WPI for real price escalation of contract services for capital expenditure,[225] but deemed that the EGWWS industry sector is more appropriate for operating expenditure labour-related services.

[224] SA Networks, *Regulatory Proposal 2015-20*, October 2014, page 267-268.
[225] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 6-143 to 6-144.

Further, the AER adopted a 62%:38% weighting of labour to non-labour costs for operating expenditure, applying EGWWS WPI forecasts for labour, and CPI as a proxy for producer price indices (**PPIs**) for non-labour. These weights were based on EI's benchmarking analysis which, in turn, was based on very dated Pacific Economic Group (**PEG**) analysis of Victorian electricity DNSPs' regulatory accounts data to 2003.[226]

The AER has consequently provided no real escalation for the (38%) non-labour component of operating costs. As shown in the table above, these costs relate predominantly to contracted services for SA Power Networks.

8.9.4.3 SA Power Networks' response to AER Preliminary Determination

SA Power Networks has reviewed EI's benchmarking analysis and the PEG analysis of Victorian electricity DNSPs' regulatory accounts data which proportionately identify costs as 62% labour based and 38% non-labour based, and considers that it does not provide a reasoned basis for the AER to apply the proposed weightings to SA Power Networks.

The PEG analysis:

- was conducted more than a decade ago;
- was based on estimated information;
- was undertaken based on quick desktop analysis in lieu of detailed discussion and input from DNSPs;
- was not undertaken for the purpose for which it is now being used by the AER;
- relates only to data from DNSPs in Victoria; and
- cannot be reasonably assumed to be reflective of current market conditions in 2015 and beyond.

EI have not provided any commentary on why the PEG analysis was adopted. In their recent response to consultants' reports on economic benchmarking they state only that

> *'[g]iven the high degree of contracting out used in Australian DNSPs, the information required to construct DNSP specific opex component weights is not readily available.'*[227]

However, EI have failed to provide any evidence that the PEG analysis is reasonable and why it would be appropriate to apply it uniformly across all DNSPs at this current time.

The PEG analysis was undertaken to conduct 'Total Factor Productivity' analysis of the Victorian electricity distribution businesses. PEG was unable to divide operations and maintenance (**O&M**) costs into labour and non-labour inputs, as a reliable time series of labour expenses was not available.[228] PEG therefore assigned what they believed to be the most appropriate available price index from the ABS to the relevant O&M cost category, on data that was available to them at that time.[229]

---

[226] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014, page 14.
[227] Economic Insights, *Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs*, 22 April 2015, page 9.
[228] PEG, *TFP Research for Victoria's Power Distribution Industry*, Report prepared for the Essential Services Commission, 2004, page 6.
[229] PEG, *TFP Research for Victoria's Power Distribution Industry*, Report prepared for the Essential Services Commission, 2004, page 13.

PEG's data source was each DNSP's Annual Regulatory Accounting Statements for the years 1996 to 2003, supplemented by costs and revenues reported in the DNSP's annual tariff findings.[230] The analysis was undertaken without input from the relevant DNSPs.

In 2010, the AER reclassified certain meter related services, as alternative control services (**ACS**). The data used by PEG in 2003 is therefore not representative, as it contains both SCS and ACS. Meter reading and meter data services are material contracted services for most, if not all, DNSPs. No attempt has been made to adjust for these expenditures by EI.

Additionally, the AER now collects detailed O&M data through its EB and CA RINs. The AER states that a key element of its Guideline is '*a standardised approach to assessment, supported by standardised datasets'*.[231] The AER has chosen to rely on outdated data from another jurisdiction, rather than conduct its own analysis of the up-to-date datasets it now collects.

The AER concludes that

> *'[b]ased on the available evidence, we consider the weightings from PEG's analysis represent reasonable benchmark weightings for efficient frontier'.*[232]

However the AER provides nothing more to substantiate this statement and presents no evidence to show that the PEG data is 'reasonable'.

Under the AER's applied weighting of 62% labour and 38% non-labour, the AER is effectively assuming that only one third of SA Power Networks contracted services are labour related and should therefore have real price escalation applied. This is based on the calculations set out in Table 8.18:

Table 8.18: AER's assumed Labour-related contract services (%)

	Assumption	Weighting
a	AER's assumed labour weighting	62%
b	SAPN's actual labour weighting	44%
c	AER's assumed labour-related contract services weighting (a-b)	18%
d	SAPN's actual contract services weighting	54%
e	AER's assumed labour-related contract services % (c/d)	33%

This is clearly not reflective of the operating contracted services utilised by SA Power Networks. SA Power Networks utilises external contracted services to deliver specialised services including, for

[230] PEG, *TFP Research for Victoria's Power Distribution Industry*, Report prepared for the Essential Services Commission, 2004, page 4.
[231] AER, *Explanatory statement to Final regulatory information notices to collect information for category analysis*, March 2014, page 1.
[232] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-58.

example, vegetation management, first call emergency response and asset inspection. In the main these services are predominantly labour based and should be escalated by a labour-based forecast of real price growth. We accept the AER's position that these services would more likely form part of the EGWWS industry sector, but do not accept the AER's weightings that will only apply real price escalation to one third of these services.

Additionally, SA Power Networks regularly reviews its services for the most efficient delivery model (ie in-house labour or outsourced services). If SA Power Networks is not adequately compensated through the AER's operating expenditure allowances for real price increases for contracted services, there is potential for it to be less cost effective to SA Power Networks in the longer term to outsource some services. Consequently this may result in decisions that are not in the '*long term interests of consumers of electricity*', as required by the National Electricity Objective.[233]

Further, the AER states that:

> *'if SA Power Networks were to include the price growth for its contracted services it would also have to include the productivity for its contracted workers in its productivity growth forecast.'*[234]

As highlighted in Section 8.9.3.3 above for labour services, it is not appropriate or valid to associate labour price growth and productivity growth forecasts.

The weighting applied to labour versus non-labour costs in the AER's preliminary decision has not been prepared on a well informed and reasoned basis and is not reflective of SA Power Networks' actual labour related services. The weighting should be increased materially for SA Power Networks' labour related contracted services.

We contend that the AER's preliminary decision to apply no real escalation to 38% of SA Power Networks' costs is not in compliance with the requirement specified in section 7A of the NEL to ensure that DNSPs have a reasonable opportunity to recover at least the efficient costs incurred in providing direct control services and that the AER has not had due regard to the operating expenditure criteria that require the AER to accept a forecast that reflects a realistic expectation of the cost inputs required for an efficient and prudent DNSP to meet the expenditure objectives.[235]

SA Power Networks accepts the AER's preliminary decision to not apply any real escalation to other non-labour operating costs such as materials and land, including some non-labour contracted services, provided that the proportion of other non-labour is reduced to reflect only materials and contracted services that are not labour related.

8.9.4.4 Revised Proposal

In our Revised Proposal, SA Power Networks has applied a forecast of the EGWWS WPI to contracted services and has not applied any real escalation to other non-labour related costs to derive a forecast of $11.5 (June 2015, $ million) for real price escalation for non-labour services.

We have reviewed our contracted services to identify any significant contracted services costs that are non-labour related. These have been reallocated to the 'other' category and hence no real escalation has been applied. This includes such costs as:

- distribution licence fee;

---

[233] Section 7 of the NEL.
[234] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20,* April 2015, page 7-59.
[235] Clause 6.5.6(c) of the NER.

- guaranteed service level payments;
- insurance premiums;
- self-insurance costs; and
- rates and taxes.

Based on our review, the mix of costs in our Revised Proposal is as shown in Table 8.19 below (note that the labour percentage has changed marginally from our Original Proposal primarily due to the AER's exclusions in calculating the efficient base year).

Table 8.19: Revised Proposal - operating expenditure costs by price category (%)

Price category	Original Proposal	Revised Proposal
Labour	43.8%	46.1%
Contracted services	54.1%	43.5%
Other (ie materials, land and non-labour services)	2.1%	10.4%

In the absence of a more appropriate measure, SA Power Networks has accepted that the EGWWS WPI is the most appropriate measure to forecast real price growth for operating expenditure contracted services. In our Revised Proposal, we have applied our forecast of the EGWWS WPI to the contracted services percentage highlighted above (ie 43.5%).

SA Power Networks has sought its own forecast of EGWWS WPI from BIS Shrapnel to apply to our contracted services as detailed in Attachment H.4 to this Revised Proposal. We contend that BIS Shrapnel's forecasts are more transparent and reliable than DAEs and should be employed if the AER chooses to apply a single consultant's estimate of the EGWWS WPI.

We note, however, that the AER has made it quite clear in recent determinations and again in its Preliminary Determination of its preference for averaging consultant's forecasts in deriving price growth[236]. Consequently, and notwithstanding SA Power Networks' belief that DAE's forecasts are not reasonable (as discussed in Section 8.9.3.3), SA Power Networks has applied an average of the DAE estimates provided with the Preliminary Determination and estimates provided by BIS Shrapnel to forecast its real escalation of contracted services.

We have used the real escalators provided in DAE's report,[237] we assume that they are independent of the CPI applied in DAE's models and therefore not impacted by changes to forecast CPI. The derivation of our EGWWS WPI forecasts is shown in Table 8.20 below.

[236] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20,* April 2015, page 7-55.
[237] DAE, *Forecast growth in labour costs in NEM regions of Australia*, 23 February 2015, Appendix A, page 11.

Table 8.20: Forecast EGWWS WPI for contracted services (%)

	2015-16	2016-17	2017-18	2018-19	2019-20
DAE Forecast	0.00%	0.20%	0.50%	0.60%	0.70%
BIS Shrapnel Forecast	1.02%	0.79%	1.34%	1.51%	1.77%
Average	0.51%	0.50%	0.92%	1.06%	1.23%

SA Power Networks contends that its revised percentage of contracted services, and the application of EGWWS WPI growth forecasts, meets the operating expenditure criteria in clause 6.5.6(c) of the NER. That is, SA Power Networks' proposed contracted services forecast reasonably reflects the efficient costs that a prudent operator would incur in achieving the operating expenditure objectives and a realistic expectation of the cost inputs required to do so.

8.10 Productivity Growth

8.10.1 Rule requirements

The Guideline requires that productivity growth be applied as part of the rate of change formula. The Guideline states that in assessing forecast productivity, the AER will likely consider (but is not limited to considering):[238]

- forecast output growth;
- forecast changes in DNSP specific business conditions;
- forecast technological change;
- how close the DNSP under consideration is to the efficient frontier in its benchmarking analysis;
- historical productivity performance; and
- any difference between industry average productivity change and the rate of productivity change at the efficient frontier.

8.10.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks did not apply a productivity adjustment to its proposed rate of change forecasts.

8.10.3 AER's Preliminary Determination

In its Preliminary Determination, the AER applied a zero per cent productivity growth for SA Power Networks.

[238] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, page 23-24.

8.10.4 SA Power Networks' response to AER Preliminary Determination

In arriving at its preliminary decision, the AER based its decision on '*expectations of the forecast productivity for an efficient service provider in the short to medium term*[239]'. This decision is consistent with the recommendation from its consultant, EI.

EI's modelling has identified negative productivity growth across the Australian electricity distribution industry between 2006 and 2013. However, EI believes that there is a reasonable prospect of operating expenditure productivity growth moving from negative productivity growth towards zero change in productivity in the next few years.[240]

The AER highlights the impact of step changes on productivity growth for Victoria and South Australia[241], but this only partially explains the negative growth across the industry. The AER has provided little conclusive evidence to support why it expects productivity growth to not continue to be negative into the 2015-20 RCP.

The AER also had regard to productivity growth across the electricity transmission and gas distribution industry over the 2006 to 2013 period.[242]

There are precedents for applying a negative productivity growth factor in similar industries, most recently by the Commerce Commission New Zealand in its determination of the price-quality paths of electricity distributors for the 1 April 2015 to 31 March 2020 period, where a growth factor of negative 0.25 per cent was applied.[243]

The Commerce Commission stated that:

> *'Our partial productivity assumption for operating expenditure is informed by evidence on past trends in productivity in New Zealand and overseas, as well as consideration of whether those trends are likely to continue in future.'*[244]

Based on the AER's preliminary decision, SA Power Networks will be expected to find considerable productivity improvements in its base operating expenditure in the 2015-20 RCP, for example for:

- **spatial network growth** – network growth due to spatial demand is not funded through the AER's output growth measures applied in its preliminary decision, and SA Power Networks will be required to fund the additional maintenance and operation costs required if this is not overturned in the AER's Final Determination;
- **labour and contractor price growth** – the labour escalation provided by the AER in its preliminary decision is considerably below what SA Power Networks is committed to pay and/or expects to pay in the 2015-20 RCP;
- **asset ageing** – despite increased funding for replacement of assets, the average age of network assets (a proxy for asset condition) continues to increase, and therefore we would expect maintenance costs to continue to rise;

---

[239] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-64.
[240] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014, page 57.
[241] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-66.
[242] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-67.
[243] Commerce Commission New Zealand, *Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020*, Main policy paper, 28 November 2014, page X9.
[244] Commerce Commission New Zealand, *Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020, Main policy paper*, 28 November 2014, page 77.

- **increasing weather events** – the Bureau of Meteorology (**BoM**) in a study of climate extremes concluded that extreme weather events will continue to increase,[245] which in turn will result in increased emergency response activity and associated costs;
- **increasing demand for data** – asset information requirements for RIN reporting (to provide 'actual' data for example) will have significant impacts on productivity through revised processes to support the granularity of data to be collected;
- **increasing safety requirements** – SA Power Networks' priority on the health, safety and wellbeing of its workers, as well as community standards and legislation, will continue to require that safety be considered first and foremost over short term efficiency gains; and
- **increasing customer expectation and services** – as more customer choice becomes available customers will demand additional information and services to assist them in their decision making.

Whilst we have included adjustments in our Revised Proposal that seeks to address the impact on productivity of a number of these factors, SA Power Networks concludes that the AER has implicitly applied a significant productivity growth adjustment in its Preliminary Determination.

SA Power Networks maintains that applying a zero per cent productivity growth is only reasonable when considered holistically and not implicitly or explicitly factored into other rate of change aspects of the operating expenditure allowance.

8.10.5 Revised Proposal

Notwithstanding these, and our comments above, SA Power Networks has accepted the application of zero per cent productivity in our Revised Proposal, consistent with the AER's Preliminary Determination.

[245] Bureau of Meteorology and CSIRO, *State of the Climate Report 2014,* page 15, (see Attachment 10.2 to the Original Proposal).

8.11 Step Changes

In our Original Proposal, we submitted step changes totalling $216.8 (June 2015, $million). In its Preliminary Determination, the AER rejected all of our step changes except for the following:

- regulatory change – NECF, of $1.3 (June 2015, $ million);
- efficient capex/opex trade-off – mobile radio migration, of $7.8 (June 2015, $ million); offset by
- regulatory change – distribution licence fee reduction, of $5.0 (June 2015, $ million).

The AER rejected each of our proposed step changes for one or more of the following overarching reasons:

1) The AER formed the view that our base year operating expenditure already reflected the cost of SA Power Networks meeting its existing regulatory obligations during the base year, and maintaining the reliability, safety and quality of supply of SCS;
2) The AER considered that many of the step changes were initiatives designed to achieve efficiencies, and that an increase in funding for such initiatives would be inconsistent with the NEM incentive based regulatory framework;
3) The AER formed the view that SA Power Networks had not provided sufficient evidence of changes in its regulatory obligations or requirements since the base year; and
4) The AER considered that there was no compelling evidence to support increases in forecast operating expenditure for SA Power Networks' customer driven initiatives or changes in community expectations.

In this section we outline where the AER's reasoning is incorrect and why the above reasoning should not apply to the assessment of the revised step changes which are further discussed in Sections 8.12 to 8.25 of this chapter.

1. Base operating expenditure already reflects the cost of meeting existing regulatory obligations, and maintaining the reliability, safety and quality of supply of SCS

The base-step-trend assessment method which the AER has chosen to adopt takes, as its starting point, the DNSP's revealed operating costs in a 'base year'. This is because total operating expenditure tends to be relatively recurrent, meaning that total operating expenditure in a recent year typically best reflects a DNSP's current circumstances.[246]

In applying the base-step-trend assessment method, the AER (expressly or implicitly) makes two assumptions:

- first, prudency and efficiency are complementary (**first assumption**); and
- secondly, actual expenditure in the base year was sufficient to achieve the operating expenditure objectives in that year[247] (ie base year opex = full compliance with applicable regulatory obligations in the base year) (**second assumption**).

[246] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-16.

[247] Ibid.

It also appears to us that a **third assumption** has been applied, namely that the actual expenditure in the base year, with appropriate escalations, will be sufficient to achieve the operating expenditure objectives in each regulatory year of the 2015-20 RCP.

First assumption

We note that the relationship between prudency and efficiency, and the complimentary nature of them, is discussed by the Australian Competition Tribunal in *Re EnergyAustralia* [2009] ACompT 8 at [137][138].

Second assumption

The second assumption - or rather the correctness of that assumption - is critical when it comes to the proper assessment by the AER of several of our revised step changes.

To restate it, the second assumption is that operating expenditure in the base year was sufficient for the DNSP to fully satisfy the operating expenditure objectives (including, in particular, compliance with all applicable regulatory obligations in the base year). But therein lies the problem, as there are circumstances in which this assumption will not hold in all cases. For example:

- There may have been changes in applicable regulatory obligations that occurred prior to the base year which had not yet been fully addressed by the DNSP in the base year. An example of this, in the case of SA Power Networks, is the changes introduced by the harmonised work, health and safety (**WHS**) legislation; and
- The DNSP may not have been fully complying with its regulatory obligations in the base year. An example of this, in the case of SA Power Networks, is the below ground inspection of no access poles where we were not complying with our obligations and determined after further investigations and analysis that a change was needed to be made to our practices to ensure compliance with our regulatory obligations moving forward.

In assessing the level of expenditure to be approved, it is critical that the AER takes such circumstances into account. If it fails to do so, the base year operating expenditure amount will produce an operating expenditure forecast that is less than that which the DNSP needs to comply with its regulatory obligations and requirements and is entitled to recover under the revenue and pricing principles.[248]

Third assumption

Like the second assumption, the apparent third assumption – or again, to be more precise, the correctness of that assumption – has a fundamental impact on the assessment by the AER of several of our revised step changes. It suggests that, absent a change to the DNSP's prescriptive (or 'black letter law') regulatory obligations and with appropriate escalation for costs, the actual expenditure in the base year will be sufficient for the DNSP to achieve the operating expenditure objectives in each of the five regulatory years of the 2015-20 RCP.

There will be circumstances where this assumption will not hold in all cases. In particular, there will be circumstances where what is required to comply with applicable regulatory obligations has evolved so as to require the DNSP in the 2015-20 RCP to take different, or additional, actions to those which it was taking in the base year and which will result in a material and on-going increase in the operating

[248] Section 7A(2) of the NEL.

expenditure required by a prudent and efficient DNSP. A good example of this in the case of SA Power Networks is its obligation under section 60(1) of the *Electricity Act 1996* (SA) (**Electricity Act**) to take reasonable steps to ensure that electricity infrastructure is safe and safely operated. This 'standard' does, and will, increase over time as the accepted standard of what is 'reasonable' changes in a way that imposes even greater obligations and costs on SA Power Networks than was previously the case.

The forecast operating expenditure allowance must reflect the operating expenditure criteria including the efficient and prudent costs of achieving the operating expenditure objective of compliance with all applicable regulatory obligations and requirements. This does not just mean the efficient costs of complying with changes to prescriptive (or 'black letter law') regulatory obligations; it also includes the efficient costs of complying with those regulatory obligations (like one to take 'reasonable steps') which, by their very nature, evolve and become more onerous over time. Once again, the revenue and pricing principles in section 7A(2) of the NEL provide that a DNSP must be provided with a reasonable opportunity to recover <u>at least</u> the efficient costs it incurs in complying with its regulatory obligations or requirements.

The AER states in several places in its Preliminary Determination that it does not forecast operating expenditure on individual programs but rather forecasts total operating expenditure, and that as operating expenditure on some programs increases, operating expenditure on others will decrease.[249] This assumption will not hold in all cases.

The AER also states that:

- while it may be prudent for SA Power Networks to change a particular business practice, this is not sufficient evidence that it needs additional funding; and
- as the cost of individual programs and projects often change over time, these changes can be accommodated without increasing total spending.[250]

This assumes, however, that the cost of changing a particular business practice to satisfy an evolving regulatory obligation will, over time, necessarily be balanced by changes in other costs drivers that existed in the base year. This assumption is not sound where the cost of complying with new obligations is material and on-going. In such a scenario, additional funds must be found to comply with the relevant obligation. While cost will obviously fluctuate from year to year, it is not realistic to assume that material cost increases can be met without having to cease other programs that were undertaken prudently and efficiently in order to comply with the operating expenditure objectives in the base year.

A prudent change in business practices which is driven by the need to comply with an evolving regulatory obligation or a regulatory obligation which was not being complied with in the base year should, under the operating expenditure criteria and the revenue and pricing principles, be funded provided the cost is efficient.

This is further supported by the fact that the AER found that SA Power Networks is operating at the efficiency frontier. We cannot simply be expected to 'find the money' from elsewhere to fund additional programs that are needed to comply with our regulatory obligations.

While each of the rejected step changes results in a material and on-going increase in the total operating expenditure required by a prudent and efficient DNSP, the combined effect of rejecting all of

---

[249] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-78.

[250] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-80.

these step changes and suggesting that they should be funded from the efficient base year operating expenditure is to deny SA Power Networks the ability to recover its efficient costs of complying with its regulatory obligations and exposes it to a significant shortfall between its total operating expenditure allowance and its real cost of achieving the operating expenditure objectives (including in particular, complying with its regulation obligations and requirements).

Summary

In summary:

- Where an efficient DNSP (like SA Power Networks) would have incurred materially higher expenditure to meet the operating expenditure objectives in its base year, and would have sustained that increase in subsequent years, it must follow that the overall level of operating expenditure in the base year was not what a prudent and efficient DNSP would have incurred. A prudent DNSP, acting efficiently, would have spent more. An operating expenditure forecast, derived using the base-step-trend method, will fail to satisfy the operating expenditure criteria if it does not reflect this increase in costs via a step change;
- Similarly, where the actions that must be taken to comply with a regulatory obligation have changed since the base year, resulting in a material and sustained increase in the cost of complying with that obligation, the logic that underpins the AER's own method for determining an operating expenditure forecast indicates that such costs must be included in the forecast operating expenditure allowance; and
- To recognise the validity of a step change to fund a material increase in the cost of complying with a changed ('black letter law') regulatory obligation, while denying the validity of a step change in the other circumstances outlined above, demonstrates an inconsistency in the AER's approach to determining a DNSP's operating expenditure forecast. In each case, the basis for the assumption that underpins the AER's base-step-trend method – that expenditure in the base year was (and will continue to be) sufficient to meet the operating expenditure objectives – does not hold. In each case, a step change is justified.

2. Several proposed step changes are for initiatives designed to achieve efficiencies. An increase in funding for such initiatives would be inconsistent with the incentive based regulatory framework

The implementation of some programs may over the long term lead to costs savings but will initially require a material and sustained increase in funding to establish the program over the relevant RCP.

There is also a further aspect of 'efficiency' that the AER fails to address. The AER appears to only turns its mind to questions of 'productive efficiency'. This is only one aspect of economic efficiency. Economic efficiency also includes allocative efficiency. The AER fails to address issues of 'allocative efficiency'. As a result, the AER fails to consider projects that provide broader benefits to consumers (ie over and above the regulated requirements) and therefore, efficient from an allocative efficiency perspective.

If consumers are willing to pay for enhanced services, then it is not efficient for a DNSP to be refused sufficient funding to deliver those services. In other words, it will be inefficient when customers want to buy a better level of service from the DNSP, and the DNSP is willing to provide that better level of service to prevent that from occurring. The AER’s failure to consider allocative efficiency prevents this potential 'transaction' between the DNSP and consumers, it is consumers that lose out as a result.

In the case of our proposed vegetation management programs, which have been driven by consumers' significant concerns about safety and amenity expressed during our robust Customer Engagement Program (**CEP**), there is evidence of consumers' willingness to pay for those programs. This evidence supports the allocative efficiency of these programs. To ignore this evidence would be contrary to the

National Electricity Objective to *'promote efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity'*.

Further detail in relation to this issue is provided in Attachment H.11: *NERA Funding Projects that Provide Customer Benefits*.

3. We could find little evidence of changes in SA Power Networks' regulations or requirements

The AER's assertions, in its Preliminary Determination, that it could find little evidence of changes in SA Power Networks' regulatory obligations or requirements, were largely focussed on regulatory obligations or requirements that are prescriptive (or 'black letter') in nature.

We consider that we provided quite clear evidence to the AER in, or with, our Original Proposal as to the nature and extent of changes in relevant regulatory obligations or requirements. Nevertheless, additional explanations and evidence are provided in, or with, this Revised Proposal.

As we have explained above in relation to the AER's approach to base year operating expenditure, prescriptive (or 'black letter') regulatory obligations or requirements are but one category only. In SA Power Networks' specific case, a key regulatory obligation imposed on it is that set down by section 60(1) of the Electricity Act. That section requires SA Power Networks to take reasonable steps to ensure that electricity infrastructure is safe and safely operated. The 'standard' of what is reasonable clearly evolves and increases over time, thereby imposing even greater obligations (and therefore costs) on SA Power Networks than was previously the case. The AER has failed to adequately take this into account in its preliminary decision on our proposed step changes.

4. There was no compelling evidence to support increases in forecast operating expenditure for SA Power Networks' customer driven initiatives or changes in community expectations

In Section 8.2 above, we explained how our Original Proposal sought to ensure consistency with the National Electricity Objective and the requirements of the NER, by developing our operating expenditure program such that it took account of key operating environment factors, including:

- the need to comply with all applicable regulatory obligations and requirements, including those relating to safety, service standards and asset management practices;
- emerging changes in applicable regulatory obligations, including but not limited to Power of Choice reform program developments that reflect significant changes in how the distribution network will operate in the future;
- ongoing rapid connection rates of new customer technologies such as solar photo-voltaic (**PV**) panels; and
- ongoing changes in customers’ expectations of various aspects of our services to them.

Again, we have been proactive and thorough in addressing these factors including through unprecedented efforts to capture and understand customer and stakeholder perspectives on many of them throughout the course of our CEP. Our CEP is discussed at Chapter 3 of this Revised Proposal.

Our Original Proposal also went to great lengths to explain how our operating (and capital) expenditure forecasts relate to our many areas of service provision to our customers. This was achieved through a series of chapters (chapters 9 to 16 of the Original Proposal) that addressed the individual service areas, applicable legal and regulatory obligations, current and emerging issues relevant to the area, CEP feedback, and how we addressed the CEP feedback in our forecasts. The chapters, and the key links to our operating expenditure forecasts, are shown in Table 8.21.

Table 8.21: How our Original Proposal addressed customer concerns

Original Proposal chapter	Key links to our operating expenditure forecasts
Chapter 9 'Keeping the power on for South Australians'	Network inspections, safety operations and asset management, substation maintenance
Chapter 10 'Responding to severe weather events'	Telecommunications network
Chapter 11 'Safety for the community'	Bushfire risk mitigation, asset inspections
Chapter 12 'Growing the network in line with South Australia's needs'	NECF customer charging changes
Chapter 13 'Ensuring power supply meets voltage and quality standards'	Flexible load management
Chapter 14 'Serving customers now and in the future'	IT systems supporting billing, customer service and cost reflective tariffs
Chapter 15 'Fitting in with our streets and communities'	Vegetation management
Chapter 16 'Capabilities to meet our challenges'	IT systems supporting workplace safety, property, vehicle fleet and other operating environment changes

From an examination of the content of these chapters in the Original Proposal (and numerous other components of our Original Proposal), it is self-evident that our Original Proposal provided significant evidence in terms of how our operating (and capital) expenditure forecasts addressed the concerns of our customers.

A number of our proposed step changes are clearly justified as being efficient by reference to customer concerns because those concerns were clearly expressed in our CEP that was both representative of our customer base and of the South Australian population, as well as being robust and academically sound in its design and implementation. The AER will err in its obligations under the NER if it fails to give weight to such preferences.

We have undertaken a comprehensive review of the Original Proposal step changes based on the AER's preliminary decision, changes in circumstances subsequent to the Original Proposal and other relevant aspects of the Revised Proposal (for example, the capital expenditure forecast). As a result of this review, we have refined the number of step changes included in the revised operating expenditure forecast of \$140.0 (June 2015, \$ million), as summarised in Table 8.22.

Table 8.22: SCS step change summary 2015-20 RCP (June 2015, $ million)

	Original Proposal	Preliminary Determination	Revised Proposal	Comment
Legal and regulatory	**105.0**	**(3.7)**	**59.7**	
- Asset inspections	42.1	0.0	34.7	Sections 8.12-8.13 see below
- Workplace health and safety	12.9	0.0	9.0	Section 8.14
- Energy laws and regulations	48.6	1.3	21.0	Sections 8.15-8.17, see below (NERL)
- Environmental management	1.4	0.0	0.0	Accept, see below
- Distribution licence fee (1)		(5.0)	(5.0)	Section 8.18
Capital program impacts	**69.6**	**7.8**	**37.4**	
- Information Technology (net)	43.9	0.0	19.4	Section 8.19
- Mobile Radio	7.8	7.8	12.8	Section 8.20
- Other Telecommunications	8.8	0.0	0.0	Accept, see below
- Non network solution (2)		0.0	1.3	Section 8.21
- Data quality	3.9	0.0	3.9	Section 8.22
- Substation maintenance	2.4	0.0	0.0	Accept, see below
- Condition monitoring	1.8	0.0	0.0	Accept, see below
- Flexible load management	1.0	0.0	0.0	Accept, see below

	Original Proposal	Preliminary Determination	Revised Proposal	Comment
Customer driven initiatives	**41.6**	**0.0**	**42.9**	
- Vegetation management	31.9	0.0	33.2	Section 8.23
- Customer services	4.3	0.0	4.3	Section 8.24
- Community safety	5.4	0.0	5.4	Section 8.25
Financing related matters	0.6	0.0	0.0	Accept, see below
Total Step Changes	**216.8**	**4.1**	**140.0**	

Note:

1) Licence Fee classified in the Original Proposal as a base year adjustment ($5.5 (June 2015, $ million) reduction).

2) Non Network solution classified in the Original Proposal as a base year adjustment ($1.4 (June 2015, $ million)).

Asset inspections

In its Preliminary Determination, the AER rejected our proposed asset inspection step changes. SA Power Networks does not accept the AER's preliminary decision as our regulatory obligations and requirements require us to increase the volume of asset inspections during the 2015-20 RCP. The reasons for this are explained in Sections 8.12 to 8.13 of this chapter.

Workplace health and safety

In its Preliminary Determination, the AER rejected our proposed workplace health and safety step changes. SA Power Networks does not accept the AER's preliminary decision as our obligations under the WHS Act require us to take these steps in the 2015-20 RCP to ensure the safety of our employees and the general public. The reasons for this are explained in Section 8.14 of this chapter.

Energy laws and regulations (excluding NERL)

In its Preliminary Determination, the AER accepted our National Energy Customer Framework (**NECF**) step change of $1.3 (June 2015, $ million) but rejected the step changes relating to Demand Side Participation (**DSP**) and Regulatory Information Notices (**RINs**). We accept the AER's preliminary decision to include NECF as a step change (refer Section 8.15). However we do not accept the AER's preliminary decisions in relation to DSP and RIN, as these step changes have arisen as a result of changes in our regulatory obligations and requirements. The reasons for this are explained in Sections 8.16 to 8.17 of this chapter.

Energy laws and regulations – NERL

A step change of $4.3 (June 2015, $ million) was included in our Original Proposal in relation to the termination of the derogation, under clause 90 of the NERL. The termination of this derogation would have required SA Power Networks, from 1 July 2015, to notify customers four days in advance of planned outages less than 15 minutes in duration. The South Australian Government subsequently advised SA Power Networks and the AER, that an extension of the derogation has been granted to 30 June 2020. We therefore accept the AER's position that a step change is not required for the 2015-20 RCP but note that a step change will be required in the 2020-25 RCP when the derogation does ultimately terminate.

Environmental management

In its Preliminary Determination, the AER rejected our proposal to recruit two additional environmental advisors dedicated to managing changing environmental laws and community expectations with respect to the environment. We have decided not to further pursue this proposal.

Distribution licence fee

In its Preliminary Determination, the AER accepted our revised negative adjustment of $5.0 (June 2015, $ million) relating to the distribution licence fee as a step change. The Original Proposal adjustment was revised from $5.5 (June 2015, $ million), following advice from the South Australian Minister for Minerals, Resources and Energy. We accept the AER's preliminary decision, with further explanation provided in Section 8.18 of this chapter.

Information Technology

In its Preliminary Determination, the AER rejected our proposed Information Technology (**IT**) step changes. SA Power Networks does not accept the AER's preliminary decision. We have, however, reassessed the IT step changes related to our revised IT capital expenditure program and have only included four of the original IT step changes in our Revised Proposal. The reasons for this are explained in Section 8.19 of this chapter.

Mobile radio

In its Preliminary Determination, the AER accepted our proposed step change for mobile radio on the basis that it represented an efficient capex/opex trade-off. The AER's preliminary decision is contingent upon the finalisation of the supporting business case and discussions with the SA Government. The Revised Proposal reflects the SA Government's updated letter of offer to SA Power Networks to migrate to the SA Government Radio Network (**SAGRN**), plus an operating expenditure adjustment to correct the classification of the upfront one-off payment. Further explanation is provided in Section 8.20 of this chapter.

Other telecommunications

In its Preliminary Determination, the AER rejected our other Telecommunication step changes of:

- incremental carrier, radio licensing and planning costs of $5.2 (June 2015, $ million), primarily associated with the forecast increased number of intelligent devices proposed to be installed in the network; and

- additional Telecommunication Network Management Centre (**TNOC**) resources of $3.6 (June 2015, $ million), required as a result of the increased complexity of the Telecommunications Network.

As outlined in Section 7.12 of this Revised Proposal, we are now deferring the installation of the majority of network monitoring devices until the 2020-25 RCP and only planning to deploy a small number of grid-side monitoring devices in the 2015-20 RCP. As a result, there will only be a small incremental operating telecommunication cost associated with this strategy in the 2015-20 RCP in respect of which we accept the AER's preliminary decision.

As outlined in Section 7.17 of this Revised Proposal, we are proposing to invest in more efficient TNOC Network Management Systems (**NMS**) to manage increasing telecommunications requirements. On the basis that the new NMS is accepted by the AER in the Final Determination; we can maintain our existing resourcing levels and therefore accept the AER's preliminary decision that the TNOC step change is not required.

Non network solution

In its Preliminary Determination, the AER rejected the incremental costs associated with the non network Bordertown solution which was implemented half way through the 2013/14 base year. SA Power Networks does not accept the AER's preliminary decision, as this decision is inconsistent with the NEO and the intent of the Regulatory Investment Test for Distribution (**RIT-D**) process. Further explanation is provided in Section 8.21 of this chapter.

Data quality

In its Preliminary Determination, the AER rejected the increased resourcing required to improve customer data quality. SA Power Networks does not accept the AER's preliminary decision, as we are required to provide quality data that meets customer and market information regulatory requirements. The reasons for this are explained in Section 8.22 of this chapter.

Substation maintenance

In its Preliminary Determination, the AER rejected our proposed incremental costs required to undertake the live-line maintenance of substation disconnectors in lieu of maintenance in a de-energised state. We have decided not to further pursue this proposal.

Condition monitoring

In its Preliminary Determination, the AER rejected our proposed need for additional asset management and field staff to further implement a condition based replacement strategy. We have decided not to further pursue this proposal.

Flexible load management

In its Preliminary Determination, the AER rejected our proposed need for costs associated with a new database to track devices compliant with the Australian Standard for electric vehicles, battery storage and air conditioning and for an advertising campaign to promote take up products where the load can be controlled dynamically. We have decided not to further pursue this proposal.

Vegetation management

In its Preliminary Determination, the AER rejected our proposed vegetation management step changes. SA Power Networks does not accept the AER's preliminary decision for a number of reasons, including the AER's rejection of initiatives arising from our CEP. The reasons for this are explained in Section 8.23 of this chapter.

Customer services

In its Preliminary Determination, the AER rejected our proposed customer service step changes. SA Power Networks does not accept the AER's preliminary decision for a number of reasons, including the AER's rejection of initiatives arising from our CEP. The reasons for this are explained in Section 8.24 of this chapter.

Community safety

In its Preliminary Determination, the AER rejected our proposed community safety step changes. SA Power Networks does not accept the AER's preliminary decision for a number of reasons, including the AER's rejection of initiatives arising from our CEP. The reasons for this are explained in Section 8.25 of this chapter.

Financing related matters

In its Preliminary Determination, the AER rejected our proposed step changes relating to higher insurance premiums of $3.0 (June 2015, $ million) and lower superannuation costs of $2.4 (June 2015, $ million). Although we do not agree with the AER's assessment of these step changes, we nevertheless accept the AER's preliminary decisions.

Sections 8.12 to 8.25 of this chapter describe the revised operating expenditure forecasts in relation to step changes that SA Power Networks considers must be provided for in the AER's Final Determination.

8.12 Legal and Regulatory: Asset Inspections - No Access Poles

8.12.1 Rule requirements

SA Power Networks is required, under Sections 6.2 (Overhead Subtransmission Lines) and 6.3 (Overhead Distribution Lines) of its Network Maintenance Manual, to inspect all poles within a defined cycle. This includes the inspection of the below-ground level portion of all poles for corrosion. There is no exemption from the inspection obligation in relation to 'no access' poles set out in the Network Maintenance Manual.

SA Power Networks is required to comply with its Network Maintenance Manual by Section 4.2 of its Safety, Reliability, Maintenance and Technical Management Plan (**SRMTMP**).

SA Power Networks is required, under the conditions of its Distribution Licence and Section 25 of the Electricity Act, to comply with its ESCoSA approved SRMTMP.

8.12.2 SA Power Networks' Original Proposal

SA Power Networks has approximately 55,000 'no access' poles, which represent about 18% of its 'urban' pole population.

'No access poles' is a reference to poles where the footings of the poles are covered at ground level with bitumen, concrete or paving. Inspecting a 'no access' pole involves a visual examination of the pole footings. This requires an asset inspector to remove the ground covering from around the pole to expose the steel just below ground level, take measurements, calculate and assess the level of corrosion in the pole and then reinstate the ground covering around the pole.

Limited inspections of 'no access' poles were undertaken during the 2010-15 RCP. During this period SA Power Networks usually inferred the below ground condition of a no access pole based on the above ground condition of the no access pole. This practice was considered a prudent risk management decision in the circumstances as 'no access' poles are expensive to inspect (due to access issues), and SA Power Networks believed that the inferred condition was a valid indicator of the actual below ground level condition. SA Power Networks also assumed that these poles would be degrading at a lower rate than other poles, and so the below ground level condition would be degrading at a lower rate than the above ground level condition. This practice is not in strict compliance with the SRMTMP.

However, for the reasons outlined below we formed the view that our duty to take 'reasonable steps' to ensure that the distribution system is safe and safely operated (together with our obligations under the Network Maintenance Manual) requires us to carry out actual inspections of the below ground level condition of 'no access' poles during the 2015-20 RCP.

Our Original Proposal included a forecast of $23.4 (June 2015, $ million) for this step change.

Further detail was provided in Section 1.1.1 of Attachment 21.13 to the Original Proposal.

8.12.3 AER's Preliminary Determination

The AER rejected this step change because it formed the view that:

- the program is not driven by a new regulatory obligation;
- funding is not provided for individual projects or programs, but rather at a total 'opex' level and a DNSP should be able to reallocate funds to meet existing regulatory or legal requirements; and

- the program gives rise to efficiencies as it should avoid reactive emergency response operating expenditure and higher cost reactive replacement and funding of this type of program would be inconsistent with the incentive schemes.

8.12.4 SA Power Networks' response to AER Preliminary Determination

We clearly have a prescriptive regulatory obligation to inspect 'no access' poles under our ESCoSA approved SRMTMP. This obligation is in addition to our general obligation under section 60 of the Electricity Act to take reasonable steps to ensure that our electricity infrastructure is safe and safely operated.

As discussed above, SA Power Networks' historical risk management approach to 'no access' poles was to infer the below ground-level condition based on the above ground condition. This practice is not in compliance with the SRMTMP.

During the 2010-15 RCP, Western Power, the distributor in Western Australia, was criticised for following similar practices and was directed by its safety regulator to inspect all poles. This triggered us to reassess our own practices by undertaking a limited number of 'no access' pole inspections to determine whether the inferred condition of our 'no access' poles was valid. We also undertook a review of other DNSPs in Australia with regard to their inspection practices of 'no access' poles.

Our inspections of 'no access' poles demonstrated that our assumption concerning the inferred condition of our 'no access' poles was not valid. In addition, our review of the practices of other DNSPs found that we were the only DNSP not performing below-ground inspections of 'no access' poles.

The condition of our 'no access' poles is critical because these poles are largely located in urbanised areas where they are in close proximity to the public and their failure poses a serious safety hazard. A pole failure can cause serious harm to the public and significant damage to property. Under the right circumstances, a catastrophic failure of one pole can cause a cascade failure of multiple poles along the line.

Further detail in relation to the findings of these inspections, including an analysis of the failure rates of 'no access' poles, is set out in Attachment H.5: *SA Power Networks Opex Step Change – No Access Poles* to this Revised Proposal.

These findings indicated that we needed to change our practices in relation to inspecting 'no access' poles in order to ensure that:

- we are complying with the regulatory obligations and requirements set out in our SRMTMP;
- we are taking reasonable steps to ensure that our 'no access' poles are safe and safely operated in accordance with section 60 of the Electricity Act;[251] and
- our practices are in line with good electricity industry practice.

For these reasons, SA Power Networks has expanded its inspection program to include all 'no access' poles during the 2015-20 RCP.

[251] Our obligation to take reasonable steps under section 60(1) of the *Electricity Act* reflects the common law duty in negligence and is informed by various factors including good electricity industry practice.

In expanding its inspection program, SA Power Networks has assessed the costs and benefits associated with a number of different approaches to addressing this risk. This analysis can be found in Section 1.1.1 of Attachment 21.13 (*Opex Step Changes*) and Supporting Document 20.13 (*Asset Inspection Strategy Business Case*) to the Original Proposal and Attachment H.5 to this Revised Proposal.

The Office of the Technical Regulator (**OTR**) is aware of SA Power Networks' non-compliance with the SRMTMP with respect to 'no access' poles and we are working with the OTR to rectify this non-compliance during the 2015-20 RCP. The OTR has accepted that the inspection of 'no access' poles will be undertaken in accordance with our obligations under the SRMTMP and our network policies during the 2015-20 RCP and beyond.

Obtaining better condition information will enable SA Power Networks to proactively replace poles prior to failure. This allows us to undertake a more detailed assessment of the future performance of poles and prudently replace poles when the risk of failure becomes evident so as to avoid public safety risks.

Based on the above, the AER is correct in finding that inspecting 'no access' poles is not a new regulatory obligation or requirement. However, the AER has failed to recognise that the actual expenditure in the base year is **not** sufficient to achieve the operating expenditure objectives in that year in relation to this program because the assumption that SA Power Networks was fully complying with the obligation to inspect 'no access' poles in the base year is incorrect.

As discussed earlier in this chapter, the argument that providing funding for total operating expenditure and not individual programs or projects justifies the rejection of this step change is not valid. We are required under our regulatory obligation to inspect 'no access' poles. The efficient base year operating expenditure did not include these costs and these costs represent a material and on-going increase in the total operating expenditure required to achieve the operating expenditure objectives as compared to our efficient base year operating expenditure. To decide to reject this step change based on an assumption about the sufficiency of our base year operating expenditure is not consistent with the AER's stated approach to step changes set out in the AER's Expenditure Forecast Assessment Guideline.

In addition, the AER's concern that this program gives rise to efficiency gains is misunderstood. This program is not driven by efficiency benefits in our cost base. Rather, this program is driven by the need to avoid the safety risk associated with pole failures. We accept there could be an effect on other funding mechanisms such as the STPIS and reactive responses and replacements, but our analysis reflects that this will be immaterial over the 2015-20 RCP.

Summary

SA Power Networks has a prescriptive regulatory obligation to inspect 'no access' poles under its ESCoSA approved SRMTMP.

In the 2013/14 base year, SA Power Networks did not undertake 'no access' poles inspections. This practice was not in compliance with SA Power Networks' regulatory obligations. It follows that the efficient base year operating expenditure did not include the expenditure required to comply with this regulatory obligation.

Rectifying this non-compliance will require SA Power Networks to incur a material and ongoing increase in costs and SA Power Networks should be given a reasonable opportunity to recover **at least** the efficient costs of complying with this regulatory obligation.

To decide to reject this step change based on an assumption about the sufficiency of our base year operating expenditure is not consistent with the AER's stated approach to step changes set out in the AER's Expenditure Forecast Assessment Guideline.

8.12.5 Revised Proposal

Our Revised Proposal includes a revised forecast for this step change of $21.8 (June 2015, $ million) as set out in Table 8.23.

This revised forecast takes into account updated quotes from a number of service providers that have resulted in a small reduction in the unit costs associated with this step change.

Further information on these unit costs and the forecast operating expenditure for this step change can be found in Attachment H.5 to this Revised Proposal.

Table 8.23: Revised no access poles inspection step change SCS for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
No Access Poles*	4.7	4.7	4.7	4.7	2.9	**21.8**

* Does not add due to rounding

8.13 Legal and Regulatory: Asset Inspections - Bushfire frequency

8.13.1 Rule requirements

This step change in operating expenditure forms part of SA Power Networks' proposed bushfire mitigation program for the 2015-20 RCP.

As discussed in Section 7.6 of this Revised Proposal, SA Power Networks is required by section 60 of the Electricity Act to take reasonable steps to ensure that its distribution system is safe and safely operated. This obligation is supplemented by SA Power Networks' obligation under clause 5.2.1(a) of the NER and parallels its duty of care under the common law of negligence.

A number of factors inform the current meaning of the obligation to take reasonable steps to ensure our network is safe and safely operated, including the findings from the Victorian Bushfires Royal Commission (**VBRC**) and the Power Line Bushfire Safety Taskforce (**PBST**).

8.13.2 SA Power Networks' Original Proposal

SA Power Networks' current asset inspection cycles are driven solely by the corrosion zone in which the asset inspection takes place, resulting in either a five or 10 year inspection cycle. Whilst there are some Bushfire Risk Areas (**BFRAs**) in high corrosion zones, the majority of BFRAs are located in low corrosion zones. This means that the typical period for detailed asset inspections in BRFAs is currently ten years.

SA Power Networks engaged Jacobs to review its bushfire risk mitigation practices, including its asset inspection practices. In its report, Jacobs recommended that SA Power Networks increase the frequency of asset inspections in all BFRAs from ten years to five years.

The recommendation to increase the frequency of asset inspections in all BFRAs was driven by the findings of the VBRC, the fact that other DNSPs across Australia inspect assets every two and a half to five years in BFRAs and the fact that the frequency of SA Power Networks' asset inspections was well out of step with good electricity industry practice.

For this reason, SA Power Networks increased the frequency of detailed asset inspections in BFRAs to every five years in 2014/15 and will continue this inspection cycle during the 2015-20 RCP.

Our Original Proposal included a forecast of $15.6 (June 2015, $ million) for this step change.

Further detail was provided in Section 1.1.3 of Attachment 21.13 to the Original Proposal.

8.13.3 AER's Preliminary Determination

The AER accepted that it would be prudent and good practice for SA Power Networks to increase the frequency of asset inspections in BFRAs based on comparative asset inspection practices in the NEM.[252]

[252] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-79.

However, the AER rejected this step change because:

- the AER applied the view that funding is not provided for individual projects or programs, but rather at a total ‘opex’ level and a DNSP should be able to reallocate funds to meet existing regulatory or legal requirements; and
- the AER had concerns in respect of the forecasting approach, model and assumptions used by SA Power Networks to estimate the incremental cost of the pole inspections.

8.13.4 SA Power Networks’ response to AER Preliminary Determination

As set out in our Original Proposal and highlighted in the Jacobs report, the frequency of SA Power Networks' BFRA asset inspections in the 2010-15 RCP are well out of step with good electricity industry practice.

For this reason, Jacobs recommended SA Power Networks increase the frequency of asset inspections in all BFRAs. In light of this recommendation, and in order to comply with our obligations under section 60(1) of the Electricity Act, clause 5.2.1(a) of the NER and the WHS Act and to address the concerns of consumers in relation to bushfire safety, SA Power Networks needs to reduce the inspection cycle for assets in BFRAs to five year cycles.

It is clear that continuing to inspect assets in BFRAs every ten years will not discharge the duty to take reasonable steps to ensure that the distribution system is safe and safely operated. Moving to a five year inspection cycle represents a reasonable step that we are required to take in order to discharge our obligation to ensure that the distribution system is safe and safely operated. It also reflects good electricity industry practice. This has been acknowledged by the AER.

For these reasons, SA Power Networks has increased the frequency of its asset inspections in BFRAs to every five years from 2014/15 and will continue to do so during the 2015-20 RCP.

In expanding its inspection program, SA Power Networks has assessed the costs and benefits associated with a number of different approaches to addressing this risk. This analysis can be found in Section 1.1.3 of Attachment 21.13 (*Opex Step Changes*) and Supporting Document 20.13 (*Asset Inspection Strategy Business Case*) to the Original Proposal and Attachment H.6: *SA Power Networks Bushfire Safety – Opex Inspection Cycle Step Change* to this Revised Proposal.

In its Preliminary Determination, the AER accepted that it would be prudent and good practice for SA Power Networks to increase the frequency of asset inspections in BFRAs.

Despite this fact the AER decided that this is merely a change in business practice and SA Power Networks does not need additional funding in relation to this change.

This is not a change in business practice. SA Power Networks’ business practice has always been to comply with its regulatory obligations and good electricity industry practice. What has changed is not SA Power Networks’ business practices but the steps that SA Power Networks needs to take in order to discharge its regulatory obligations and comply with good electricity industry practice.

When that change occurred is largely irrelevant. The AER has acknowledged that this is now 'good practice'. SA Power Networks implemented this change during the 2014/15 regulatory year. It is likely that the change in the steps required to comply with our regulatory obligation actually occurred earlier in the 2010-15 RCP. What matters is that SA Power Networks must adopt this step now to comply with its regulatory obligation and SA Power Networks did not implement this step during or prior to the 2013/14 base year.

This increase in asset inspections in BFRAs was not reflected in the 2013/14 base year operating expenditure because SA Power Networks' inspection cycle for assets in BFRAs during the 2013/14 base year was still every ten years. The additional operating expenditure associated with moving to a 5 year inspection cycle for assets in BFRAs is material and ongoing and will be reflected in our operating expenditure for the base year for the 2020-25 RCP.

This means that the actual expenditure in the 2013/14 base year is **not** sufficient to achieve the operating expenditure objectives in that year or during the 2015-20 RCP.

This approach was supported by the VBRC in its Final Report where, in recommending that asset inspections be undertaken more frequently, it stated that a move to a shorter inspection cycle is a material change in obligations and necessitates additional expenditure.[253]

As discussed earlier in this chapter, the argument that providing funding for total operating expenditure and not individual programs or projects justifies the rejection of this step change is not valid.

In addition, the AER's concerns in respect to the forecasting approach, model and assumptions used by SA Power Networks to estimate the incremental cost of inspections is not justified. We provided a significant amount of information to the AER in relation to this step change as part of our Original Proposal.[254] However, to assist the AER in alleviating its concerns we have included a detailed explanation of our inspection forecasting model in Attachment H.6 to this Revised Proposal.

Summary

We are required under our regulatory obligations to inspect assets in BFRAs at least every five years.

Our efficient base year operating expenditure did not include the cost of undertaking these additional inspections and these costs represent a material and on-going increase in the total operating expenditure required to achieve the operating expenditure objectives as compared to our efficient base year operating expenditure.

To decide to reject this step change based on an assumption about the sufficiency of our base year operating expenditure is not consistent with the AER's stated approach to step changes set out in the AER's Expenditure Forecast Assessment Guideline.

We have provided further information in Attachment H.6 to this Revised Proposal which addresses the AER's concerns in relation to the forecasting approach, model and assumptions used by SA Power Networks to estimate the incremental cost of the inspections.

8.13.5 Revised Proposal

Our Revised Proposal includes a forecast for this step change of $12.9 (June 2015, $ million), set out in Table 8.24.

[253] Victorian Bushfires Royal Commission, *'The 2009 Victorian Bushfires Royal Commission Final Report'*, 31 July 2010, Vol II, Ch 4 (Electricity-Caused Fire), page 161.
[254] See eg, section 1.1.3 of Attachment 21.13 and Supporting Document 20.13 to the Original Proposal.

Table 8.24: Revised bushfire asset inspection frequency step change SCS for the 2015-20 RCP (June 2015, $million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Bushfire Inspection	2.3	2.6	2.6	2.7	2.7	**12.9**

8.14 Legal and Regulatory: Workplace Health and Safety

8.14.1 Rule requirements

SA Power Networks' activities are governed by the *Work Health and Safety Act 2012* (SA) (**WHS Act**). The 'nationally harmonised' WHS Act came into force on 1 January 2013, during the 2010-15 RCP.

SA Power Networks is 'a person conducting a business or undertaking' within the meaning of section 5 of the WHS Act. It follows that SA Power Networks owes a non-delegable duty (in respect of health and safety to both its workers and all other persons who may be affected by assets within its management) to, so far as is reasonably practicable, ensure that its workplace is without risk to the health and safety of any person.

What is required of SA Power Networks in order to satisfy these duties depends on what actions are 'reasonably practicable'.

Section 18 of the WHS Act provides that what is 'reasonably practicable' in ensuring health and safety is that which is, or was at a particular time, reasonably able to be done in relation to ensuring health and safety, taking into account and weighing up all relevant matters including:

- the likelihood of the hazard or risk occurring;
- the degree of harm that might result from the hazard or the risk;
- what the relevant person knows, or ought reasonably to know, about the hazard or the risk;
- ways of eliminating or minimising the risk;
- the availability and suitability of ways to eliminate or minimise the risk; and
- after assessing the extent of the risk and the available ways of eliminating or minimising the risk, the cost associated with available ways of eliminating or minimising the risk, including whether the cost is grossly disproportionate to the risk.

It follows that SA Power Networks must first consider what can be done to remedy any risk to health and safety, and then consider (by reference to the above matters) whether it is reasonably practicable to take the identified action.

There is a clear presumption in favour of safety ahead of cost under the WHS Act. This is consistent with the rationale behind the notion of 'reasonably practicable'. The definition of 'reasonably practicable' in section 18 of the WHS Act introduces the requirement that the cost of taking a control measure must be 'grossly disproportionate' to the risk it seeks to address before it will not be reasonably practicable to take that measure.

The use of this phrase is important as it (in part) addresses the complexities of weighing up cost and risk by promoting a transparent bias in favour of safety (ie unless the cost of a control measure is grossly disproportionate to the risk, the control measure will be reasonably practicable).

<u>There is no doubt that the WHS Act is an applicable regulatory obligation or requirement associated with the provision of SCS.</u>

In order to discharge this statutory health and safety duty, SA Power Networks must implement all control measures of which it is aware, provided that the cost of doing so is not grossly disproportionate to the risk it seeks to address. However, a typical (or standard) cost/benefit analysis is inappropriate when determining whether SA Power Networks is required to implement a particular control measure. The balancing exercise between safety and cost is weighted far more in favour of safety.

8.14.2 SA Power Networks' Original Proposal

In our Original Proposal, we outlined a number of step changes required to ensure that we are complying with our regulatory obligations and requirements under the WHS Act and WHS Regulations. These included:

- introduction of two person crews to undertake pre-bushfire season patrols, at a forecast cost over the 2015-20 RCP of $2.8 (June 2015, $ million);
- increasing resource levels in our Network Operations Centre (**NOC**), at a forecast cost over the 2015-20 RCP of $4.0 (June 2015, $ million);
- increasing fleet inspections of Elevated Work Platforms (**EWPs**) and heavy vehicles such as cranes at a forecast of $3.9 (June 2015, $ million) over the 2015-20 RCP; and
- In Vehicle Management System (**IVMS**) monitoring of our heavy vehicle fleet and our commercial vehicles, at a forecast operating cost of $2.2 (June 2015, $ million) over the 2015-20 RCP.

Further detail was provided in Section 1.2 of Attachment 21.13 to the Original Proposal.

8.14.3 SA Power Networks' response to AER Preliminary Determination

In its Preliminary Determination, the AER rejected these step changes because it formed the view that a prudent service provider would already be meeting its regulatory obligations under the WHS Act and WHS Regulations in the 2013/14 base year given that those obligations commenced on 1 January 2013 and are consistent with the former occupational health, safety and welfare legislation.

In addition, the AER was not satisfied that a prudent service provider's operating expenditure in meeting its obligations under the WHS Act and WHS Regulations should be materially different in the 2015-20 RCP to the workplace health and safety operating expenditure in the 2013/14 base year.

In relation to the proposed roll out of the IVMS, the AER acknowledged that this proposal had merit but rejected funding for the continued roll out during the 2015-20 RCP.
We have reassessed the work health and safety step changes included in our Original Proposal and have included three out of the four step changes in this Revised Proposal. We have excluded the NOC step change as we are now of the view that the expenditure associated with this step change will be covered by escalation for output growth.

Discharge of duties under WHS Act

As outlined above, SA Power Networks must ensure that, so far as is reasonably practicable, workplaces are without risk to the health and safety of any person. This includes SA Power Networks employees and contractors, and the general public.

The harmonised WHS Act commenced on 1 January 2013 after an extensive period of consultation. Like many Australian businesses, the commencement of the WHS Act has triggered SA Power Networks to re-examine its workplace practices and assess whether those workplace practices were sufficient to discharge its duty to ensure that (so far as is reasonably practicable) its workplaces are without risk to the health and safety of any person. Consistent with the approach adopted by most businesses, this is an ongoing and evolving process. SA Power Networks is continually reviewing its workplace practices to identify if any of those workplace practices need to be modified in order to properly discharge this duty.

It does not matter that the WHS Act commenced on 1 January 2013. What matters is what constitutes a reasonably practicable measure that helps to ensure that our workplaces are without risk to the health and safety of any person at a particular point in time. In the case of step changes what also matters is whether the costs that are related to implementing a required safety measure were included within the efficient base year operating expenditure.

Our requirement to take reasonable steps requires the initiatives detailed in 8.14.2 to be taken irrespective of whether that work was or was not performed in 2013/14.

The operating expenditure in 2013/14 base year did not include these costs and therefore SA Power Networks consider they are a valid step change in operating expenditure.

Asset Inspections – 2 person crews

Pre-bushfire season patrols have in the past been performed by a single person in a light vehicle. A recent review of the safety risk assessment associated with these patrols has identified that despite job safe work procedures requiring the individual to stop the vehicle before inspecting the asset, the human behaviour element and the timeframe to complete the patrols before fire danger season commencement, means that inspections have been done while the vehicle is moving.

The alternative option is to increase the number of inspectors (with consequent increase in vehicle capital and operating costs) so that the pre-summer patrols can be completed in the same timeframe prior to the start of bushfire danger season.

The requirements of the WHS Act necessitate a shift to two person inspection crews to ensure that SA Power Networks is eliminating or minimising risks to the safety of those inspection crews and the general public so far as is reasonably practicable. The shift to two person inspection crews will commence in 2014/15 and be fully operational from 2015/16.

The shift to two person's inspection crews is required in order to properly discharge our obligations under the WHS Act. It does not matter that the WHS Act commenced on 1 January 2013. What matters is what constitutes a reasonably practicable measure that helps to ensure that our workplaces are without risk to the health and safety of any person at a particular point in time. In the case of step changes what also matters is whether the costs that are related to implementing a required safety measure were included within the efficient base year operating expenditure.

Fleet Inspections

We are required to do what is reasonably practicable to eliminate or minimise health and safety risks to our workers under the WHS Act. This includes conducting fleet inspections of heavy vehicles such as EWPs and Cranes to ensure compliance with the maintenance and inspections requirements detailed in AS 2550.10 (Cranes & Elevated Platforms – Safe Use) and AS 1418.10 (Cranes, Hoists and Winches).

Following an independent review of our fleet inspection activities, SA Power Networks identified the need to increase our inspection program to ensure that our fleet remains compliant with these WHS Act requirements. A trial has been undertaken in a selected depot based on the recommended inspection regime using third party specialist providers in 2014/15 to demonstrate that the proposed improved inspection regime meets the required standards. Satisfactory completion of this trial will be the basis for adoption for the entire vehicle inspection cycle commencing in 2015/16.

The increase in our inspection program is required in order to properly discharge our obligations under the WHS Act. It does not matter that the WHS Act commenced on 1 July 2013. What matters is what constitutes a reasonably practicable measure that helps to ensure that our workplaces are without risk to the health and safety of any person at a particular point in time. In the case of step changes what also matters is whether the costs that are related to implementing a required safety measure were included within the efficient base year operating expenditure.

IVMS

The first phase of the IVMS program has been successfully implemented with the initial roll out of IVMS to 100 vehicles during 2014/15. The IVMS helps us to ensure (so far as is reasonably practicable) that our workplace is without risk to the health and safety of any person[255] by:

- managing and monitoring the safety and welfare of our mobile employees working alone in remote or risky areas; and
- measuring driver safety and behaviour and vehicle treatment.

The operating expenditure step change of $2.2 (June 2015, $ million) relates to the ongoing monitoring fees associated with the IVMS units.

IVMS are now being adopted as standard practice in many industries (for example, the mining industry has increased its use of IVMS over the last five years particularly as technology and systems have improved).

The introduction of the IVMS by SA Power Networks also followed a number of significant incidents, such as EWP vehicle roll overs, which could have resulted in fatalities. Whilst the number of vehicle incidents has remained relatively stable over the last 12 months, the severity of these incidents has reduced.

In its Preliminary Determination, the AER acknowledged the merit of our proposed IVMS but concluded that insufficient evidence was provided to support the need for IMVS to meet new legislative and WHS requirements. As set out below, this conclusion is incorrect for a number of reasons.

[255] *Work, Health and Safety Act 2012* (SA); *Electricity Act 1996* (SA).

Compliance with regulatory obligations

In its Preliminary Determination, the AER concluded that a prudent service provider would already be meeting its regulatory obligations under the WHS Act and WHS Regulations in the 2013/14 base year given that those obligations commenced in 2013 and are consistent with the former occupational health, safety and welfare legislation.

This conclusion ignores the fact that:

- these WHS initiatives are <u>now</u> clearly reasonably practicable to adopt to ensure its workplaces are without risk to the health and safety of any person (ie SA Power Networks is obligated to adopt these initiatives); and
- SA Power Networks' efficient base year operating expenditure did not include any costs on account of these WHS initiatives.

The AER also appeared to suggest that the consistency between the WHS Act and the former occupational health, safety and welfare legislation meant that SA Power Networks' efficient base year operating expenditure should have included relevant costs on account of compliance with all of its WHS obligations. Leaving to one side the question as to the extent of any consistency, SA Power Networks' efficient base year operating expenditure did not include any cost on account of these initiatives.

Material change in 2015-20 RCP operating expenditure

In its Preliminary Determination, the AER stated that it was not satisfied that a prudent service provider's operating expenditure in meeting its obligations under the WHS Act and WHS Regulations should be materially different in the 2015-20 RCP to the WHS operating expenditure in the 2013/14 base year.

SA Power Networks submits that:

- a prudent service provider would adopt these WHS measures because they are clearly reasonably practicable WHS measures;
- its efficient base year operating expenditure clearly did not include any costs on account of these WHS measures;
- these WHS measures are in addition to the WHS measures which were reflected in our efficient base year operating expenditure;
- these WHS measures do not replace or reduce the costs associated with other WHS measures; and
- the cost of implementing these WHS measures over the 2015-20 RCP is material and ongoing throughout the entire RCP and is not already captured in the base year or via the approved escalations.

Summary

The efficient base year operating expenditure did not include these WHS costs and these WHS costs represent a material and on-going increase in the total operating expenditure required to achieve the operating expenditure objectives as compared to our efficient base year operating expenditure. To decide to reject these WHS step changes based on an assumption about the sufficiency of our base year operating expenditure which is clearly incorrect, is not consistent with the AER's stated approach to step changes set out in the AER's Expenditure Forecast Assessment Guideline.

8.14.4 Revised Proposal

The Revised Proposal includes a forecast for these WHS step changes of $9.0 (June 2015, $ million) as set out in Table 8.25.

Table 8.25: Revised WHS step changes SCS for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Asset inspections	0.6	0.6	0.6	0.6	0.6	**2.9**
Fleet – inspections	0.8	0.8	0.8	0.8	0.8	**3.9**
Fleet – IVMS	0.1	0.3	0.5	0.6	0.6	**2.2**
Total WHS*	**1.5**	**1.7**	**1.8**	**2.0**	**2.0**	**9.0**

* Does not add due to rounding

8.15 Legal and Regulatory: New RIN requirements

8.15.1 Rule requirements

The AER's Better Regulation program has imposed new regulatory information notice (**RIN**) requirements on DNSPs.

Effective from 2013/14, SA Power Networks will be required to complete Economic Benchmarking (**EB**) and Category Analysis (**CA**) RINs annually, in addition to the Annual RIN and the Reset RIN it is required to complete every five years.

8.15.2 SA Power Networks' Original Proposal

The EB and CA RINs require SA Power Networks to provide the AER with a more granular level of financial and non-financial information. In addition, commencing in 2014/15 (EB) and 2015/16 (CA) respectively, the RINs must be prepared using actual rather than estimated data.

Whilst the regulatory obligation relating to the annual completion and provision of EB and CA RINs commenced in 2013/14, the scope of that regulatory obligation will significantly increase during the 2015-20 RCP because SA Power Networks is required to provide actual rather than estimated data from 2014/15 (EB) and 2015/16 (CA). This constitutes a material increase in the steps (and consequently the compliance costs) required to discharge this regulatory obligation during the 2015-20 RCP (as compared to the steps and compliance costs during the base year).

These additional costs are not reflected in the efficient base year operating expenditure because the obligation to provide actual data did not apply during the base year.

A significant majority of the level and type of financial and non-financial information required under the new RIN requirements is not currently captured by SA Power Networks existing systems and processes, and will require SA Power Networks to reconfigure or redesign these systems and processes to do so.

In our Original Proposal, we proposed a step change of $9.2 (June 2015, $ million) for a one-off collection of vegetation management data required for RIN purpose only, and the ongoing increased costs of obtaining additional field and back office resources to capture and process the data and implementing internal audits required to complete RINs. The forecast level of this step change was based on the assumption that the AER accepts our proposed RIN IT capital expenditure program. If the AER does not accept that proposed capital expenditure, then the operating expenditure associated with this step change would need to increase significantly.

Further detail was provided in Section 1.3.1 of Attachment 21.13 to the Original Proposal.

8.15.3 AER's Preliminary Determination

The AER rejected the step change on the basis that 'persuasive evidence' was not presented as to why additional costs will be incurred to meet compliance with the new RIN requirements. The AER was of the view that:[256]

- insufficient evidence was provided to demonstrate why producing actual data rather than estimated data for some cost categories would lead to a materially greater cost burden in the 2015-20 RCP;
- the volume of data to be collected annually in the 2015-20 RCP would be far less than that which the AER required to be collected in 2013/14 (because of the one-off requirement to provide eight years of economic benchmarking and five years of category analysis data in that year); after two years of preparing these RINs, SA Power Networks would have developed more efficient practices in identifying, collecting and reporting data, and these efficiencies would only increase over the 2015-20 RCP to potentially decrease SA Power Networks' RIN reporting costs; and
- in the 2013/14 base year, SA Power Networks would have incurred costs in completing its Reset RIN and, as these costs are typically only incurred towards the end of a RCP, our reporting costs would fall in the first two years of the 2015-20 RCP, offsetting any cost increase arising from reporting a greater amount of information on an actual rather than an estimated basis in the 2015-20 RCP.

In addition, the AER did not accept our proposed IT capital expenditure program forecast of $353.7 (June 2015, $ million) and included an alternative forecast of $213.6 (June 2015, $ million) in its Preliminary Determination (a reduction of 40%).

8.15.4 SA Power Networks' response to AER Preliminary Determination

The AER acknowledged in the Better Regulation Explanatory Statement for the Expenditure Forecast Assessment Guideline that:

> *'… the more detailed information requirements will increase regulatory compliance costs somewhat and may increase the complexity of the regulatory process to some degree. However, we consider that increased compliance costs are justified given the large amounts of expenditure involved and given the relatively limited information previously available to the AER in the past.'*[257]

In Section 7.15 of this Revised Proposal, we explained why the AER erred in rejecting our proposed IT capital expenditure program forecast in its Preliminary Determination. In that section, we also note that we will incur additional operating expenditure in the 2015-20 RCP if our RIN related (RIN

[256] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-82 to 7-83.
[257] AER, *Better Regulation, Explanatory Statement to the Expenditure Forecast Assessment Guideline*, November 2013, page 56.

Reporting, Enterprise Asset Management (**EAM**) and associated projects) IT capital expenditure forecast is not accepted by the AER in its Final Determination.

This RIN step change relates to a regulatory obligation that will significantly increase in scope during the 2015-20 RCP because SA Power Networks is required to provide actual data rather than estimated data from 2014/15 (EB) and 2015/16 (CA). This constitutes a material increase in the steps (and consequently the compliance costs) required to discharge this regulatory obligation during the 2015-20 RCP (as compared to the steps and compliance costs during the base year).

The exact level of the step change in operating expenditure that SA Power Networks will incur as a result of complying with this regulatory obligation will depend on whether the AER accepts our revised RIN-related IT capital expenditure forecast in its Final Determination.

If the AER accepts our revised RIN-related IT capital expenditure program forecast in its Final Determination, the amount of this step change will be significantly less than the amount that SA Power Networks would then incur if the AER does not accept our revised RIN-related IT capital expenditure forecast because collecting and providing actual data for the EB and CA RINs using our existing manual systems will materially increase our costs of complying with the RIN regulatory obligation during the 2015-20 RCP, as compared to:

- the costs incurred in our base year; and
- the additional costs that would be incurred during the 2015-20 RCP (ie in addition to the costs incurred in our base year) if our revised RIN-related IT capital expenditure forecast is accepted.

For this reason, we have discussed below what the amount of this step change will need to be if the AER:

- accepts our revised RIN-related IT capital expenditure forecast; and
- does not accept our revised RIN-related IT capital expenditure forecast.

SA Power Networks submitted a RIN Reporting Business Case with the Original Proposal. This Business Case included the increased operating expenditure costs required to embed and maintain the new RIN reporting processes. Based on the AER's response to the original RIN step change proposal, a paper has been developed (Attachment G.22 *EAM and RIN Reporting*) to provide further evidence to support our claim and to clarify what the step change will need to be if the AER does or does not accept our revised RIN-related IT capital expenditure forecast.

In its Preliminary Determination, the AER stated a number of positions, as listed in Section 8.15.3 above. We provide our response to these positions below, but in summary, it is SA Power Networks' view that:

- there is evidence to demonstrate that producing actual data costs materially more than estimated data;
- it is irrelevant that the ongoing annual volume of data for EB and CA RIN reporting purposes is less than was submitted in 2013/14 – what matters is the resources and processes required to provide actual data;
- efficiencies in the preparation of EB and CA RINs will be recognised in the 2020-25 RCP once new systems and processes are embedded which will occur progressively toward the end of 2015-20; and
- costs associated with the completion of the Reset RIN were incurred between July and August 2014, which means they were not included in the base year.

Evidence to demonstrate why producing actual data costs materially more than estimated data

In its Preliminary Determination the AER stated that insufficient evidence was provided by SA Power Networks to demonstrate why producing actual data rather than estimated data for some cost categories would lead to a materially greater cost burden in the 2015-20 RCP.

The paper in Attachment G22 '*Enterprise Asset Management and RIN Reporting*' includes a detailed analysis of the additional operating expenditure costs (ie in excess of the RIN compliance costs incurred within the 2013/14 efficient base year) which would need to be incurred if:

- the RIN-related capital expenditure IT costs are included within the total forecast capital expenditure; and
- the RIN-related capital expenditure IT costs are not included within the total forecast capital expenditure.

In particular, Attachment G.22 explains (by way of example) the current asset replacement process (manual and systems) for a power line asset and highlights the difference in effort and costs between the collection of actual data verses estimated data using the current manual processes.

Attachment G.22 clearly demonstrates that the collection of actual data as compared to estimated data in the absence of the implementation of the related IT capital projects will result in a material and ongoing increase in operating expenditure over and above the 2013/14 efficient base year operating expenditure. This represents the increase in the total forecast operating expenditure that would be required to comply with the new RIN obligations if the RIN-related IT capital projects are **not included** within the total forecast capital expenditure.

However, even if the RIN-related IT capital projects **are included** within the total forecast capital expenditure, SA Power Networks will require a material and ongoing increase in operating expenditure (over and above the 2013/14 efficient base year operating expenditure) on account of the costs that will need to be incurred in order to:

- facilitate the provision by our Vegetation Management contractor of 'actual' data via a one-off increase in vegetation scoping costs of $1.8 (June 2015, $ million) in 2016;
- train our workforce in relation to the new processes and systems;
- implement new data recording procedures and safeguards relating to data cleansing, data quality and audit (based on historical projects and lessons learned); and
- ensure full compliance with the new processes and systems.

The new systems represent a significant change to the previous asset data recording and collection systems. New processes, procedures and documents will need to be designed and implemented. Field and depot personnel will need to be trained in relation to the use of the new processes, procedures and systems. Governance arrangements to ensure the accuracy and completeness of actual data will need to be established, implemented, monitored and maintained. Internal auditors and data collection managers will need to be engaged to provide the necessary level of comfort to senior management when certifying the accuracy and completeness of the actual data included within each annual EB and CA RIN.

These costs are materially greater than the operating costs associated with the collection of estimated data because:

- the collection of actual data requires additional activities and costs to be incurred which do not need to be undertaken/incurred when producing estimated data (regardless of whether a manual or IT based system is used); and
- the collection of actual data utilising the new systems will require activities to be undertaken and costs to be incurred during the 2015-20 RCP which would not need to be incurred when producing estimated data using the current manual systems.

Annual volume of data less than 2013/14 volume of data

The AER stated, in its Preliminary Determination, that the volume of data to be collected annually in the 2015-20 RCP would be far less than the AER collected in 2013/14 (because of the one-off requirement to provide eight years of EB and five years of CA data in that year).

This statement ignores the fact that the costs related to collecting and recording actual data far exceed the cost of providing estimated data. Attachment G22 includes a detailed analysis of the difference in cost between providing actual data and estimated data. Actual data requires a positive assurance which requires significantly more scrutiny than estimated data and negative assurances (such as business processes, control testing and audit techniques like sampling, verifying, observation and substantive analysis). This would be the case whether or not actual data is collected manually or using the new IT systems. However, the proposed new IT systems would make this process far more efficient.

In addition, in order to complete the initial EB and CA RINs, resources were re-assigned from their current activities to populate RIN data, which resulted in a deferral of planned work and hide the true extent of the costs associated with populating the EB and CA RINs. Additionally, senior managers worked extended hours (at no additionally cost) over a number of months to ensure that the EB and CA RINs were populated in accordance with the AER's requirements. This once again hides the true extent of the costs associated with populating the EB and CA RINs. This practice is not sustainable over the long term and additional dedicated resources will need to be engaged to perform this function during the 2015-20 RCP. This will result in an increase in the annual cost of completing the EB and CA RINs. This would be the case even if estimated data was still being provided though to a lesser extent. Requiring the provision of actual data further exacerbates this cost differential.

Increasing efficiency will not decrease costs over the 2015-20 RCP

In its Preliminary Determination, the AER stated that, after two years of preparing these RINs, SA Power Networks would have developed more efficient practices in identifying, collecting and reporting data, and these efficiencies would only increase over the 2015-20 RCP to potentially decrease SA Power Networks' RIN reporting costs.

As referenced in Attachment G22, the Financial Management, Enterprise Asset Management and RIN Reporting capital IT projects will deliver collectively 78.5% of the ‘actual’ data required to populate the EB and CA RINs. The capability from these projects will be implemented over a period of time (based on the RIN implementation roadmap) and will not be fully implemented until approximately July 2017.

During this transition period, SA Power Networks will be changing and embedding a range of new processes across the business including the reconciliation of the estimated data originally submitted to the AER with the actual data delivered by new IT systems. SA Power Networks expects that any efficiencies that are related to the implementation of the new IT systems will not be recognised until the 2020-25 RCP (at the earliest).

Attachment G22 includes further details concerning the expected timing and size of any efficiency gains related to the implementation of the new IT systems (if the expenditure relating to those systems is accepted by the AER in its Final Determination).

Reset RIN costs were incurred after the 2013/14 base year

In its Preliminary Determination, the AER stated that, in the 2013/14 base year, SA Power Networks would have incurred costs in completing its Reset RIN, and these costs are typically only incurred towards the end of an RCP. The AER then stated that SA Power Networks' reporting costs would then fall in the first two years of the 2015-20 RCP, offsetting any cost increase arising from reporting a greater amount of information on an actual rather than an estimated basis in the 2015-20 RCP.

SA Power Networks has not considered its costs to complete the Reset RIN in the current analysis because the majority of that data is a forecast and is by definition estimated and will continue to be estimated. We also reject the assertion that the cost for populating the Reset RIN would have been incurred in the 2013/14 base year as this process was undertaken by SA Power Networks between July and October 2014. It follows that the AER conclusion in relation to the base year is incorrect.

Summary

The efficient base year operating expenditure did not include the cost of collecting and providing actual data for the EB and CA RINs. These costs will be incurred in the 2015-20 RCP in order to comply with the new RIN regulatory obligations requiring the provision of actual data from 2014/15 (to be reported in 2015/16). This obligation did not apply during the base year and these costs represent a material and on-going increase in the total operating expenditure required to achieve the operating expenditure objectives as compared to our efficient base year operating expenditure.

This is the case whether or not the AER accepts or rejects our revised RIN-related IT capital expenditure forecast. However, the level of the required step change will be significantly higher if the AER rejects our revised RIN IT capital expenditure forecast.

To reject this step change based on an assumption about the sufficiency of our base year operating expenditure is not consistent with the AER's stated approach to step changes set out in the AER's Expenditure Forecast Assessment Guideline.

8.15.5 Revised Proposal

Our Revised Proposal includes RIN-related IT capital expenditure forecasts, and we have included a revised step change related to compliance with the new RIN requirements during the 2015-20 RCP of $6.4 (June 2015, $ million) as set out in Table 8.26.

Table 8.26: Revised RIN requirements step change SCS for the 2015-20 RCP – if revised capital expenditure accepted (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
RIN Requirements	2.0	0.2	1.4	1.4	1.4	**6.4**

However, if the AER rejects our proposed RIN-related IT capital expenditure forecast then an increased step change related to compliance with the new RIN requirements during the 2015-20 RCP is $16.6 (June 2015, $ million) would be required, as set out in Table 8.27.

Table 8.27: RIN requirements step change SCS for the 2015-20 RCP – if revised capital expenditure rejected (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
RIN Requirements*	4.1	2.2	3.4	3.4	3.4	**16.6**

* Does not add due to rounding

8.16 Legal and Regulatory: NECF

8.16.1 Rule requirements

The South Australian Government partially adopted the National Energy Customer Framework (**NECF**) on 1 February 2013, with the intention of full adoption from 1 July 2015 (including the NECF connection charging obligations). The NECF applies to all customers who apply for a connection service.

8.16.2 SA Power Networks' Original Proposal

The NECF imposes a number of obligations on SA Power Networks over the 2015-20 RCP, requiring staff to undertake a number of additional or expanded activities. This includes, from 1 July 2015, the requirement to apply the AER's Connection Charge Guideline for calculating customer contributions which is more complex with greater variability in costs to consumers.

In our Original Proposal, we proposed a step change for the additional resources required to process these new charging arrangements in a consistent manner and to handle the expected increase in customer queries. The forecast cost of this initiative is $1.3 (June 2015, $ million) over the 2015-20 RCP.

Further detail was provided in Section 1.3.3 of Attachment 21.13 to the Original Proposal.

8.16.3 AER's Preliminary Determination

The AER accepted this step change agreeing that there is a requirement for additional resources to deal with the full adoption of the NECF.

8.16.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks accepts the AER's preliminary decision.

8.16.5 Revised Proposal

Consistent with our Original Proposal and the AER's preliminary decision, our Revised Proposal includes a forecast for this step change of $1.3 (June 2015, $ million), as set out in Table 8.28.

Table 8.28: Revised NECF step change SCS for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
NECF *	0.3	0.3	0.3	0.3	0.3	**1.3**

* Does not add due to rounding

8.17 Legal and Regulatory: Demand Side Participation

8.17.1 Rule requirements

Increasing Demand Side Participation (**DSP**) and emerging technologies such as battery storage and electric vehicles are changing the role of the networks from a one-way energy distribution system to an active two-way grid that connects a dynamic web of distributed consumption and generation resources. This creates new challenges in how we manage and operate the network.

The three primary factors driving these challenges are the AEMC's Distribution Network Pricing Arrangements Rule change, the AEMC's Expanding Competition in Metering and Related Services Rule change and the increased solar photovoltaic (**PV**) penetration in South Australia.

Transition to cost-reflective network tariffs

The AEMC's Distribution Network Pricing Arrangements Rule change (which was in draft at the time of our Original Proposal) was finalised on 1 December 2014 and requires us to transition to cost-reflective network tariffs during the 2015-20 RCP. This new regulatory obligation requires:

- network prices based on a new pricing objective and pricing principles which must start by July 2017;
- SA Power Networks to consult, from 2015, with retailers and consumers on the structure of network prices we propose to apply from July 2017 through to June 2020; and
- SA Power Networks to submit an initial tariff structure statement to the AER by 27 November 2015.

Introduction of full competition in metering

The AEMC's Expanding Competition in Metering and Related Services draft Rule change is expected to be finalised in July 2015, with the transition to full competition in metering to occur during the 2015-20 RCP.

Amongst other things, the Rule change proposes that retailers will be responsible for appointing a Metering Coordinator to arrange meter provision services and meter data provision services for small customer metering installations from 1 July 2017. From that date, all new and replacement meters must be Type 4 meters (smart meters).

The changes effected by the Expanding Competition in Metering and Related Services Rule change when finalised will constitute a very significant reform. This reform will impact on SA Power Networks' business processes and systems and require increased staffing levels to manage the unprecedented mass replacement of SA Power Networks' regulated Type 6 meters with third party smart meters.

Monitoring the LV network

The widespread uptake of small-scale rooftop solar PV generation since 2011 has led to unprecedented two-way energy flows and voltage variations in SA Power Networks' Low Voltage (**LV**) network.

As solar PV penetration continues to increase in the 2015-20 RCP, modelling indicates that in older areas of the network our historical approach to managing power quality will no longer be sufficient to meet our regulatory obligation to maintain voltage levels at customer premises within the range specified in AS60038.

Regulation 46 of the *Electricity General Regulations 2012* (SA) requires SA Power Networks, as the operator of a distribution network, to ensure that its network is designed, constructed, operated and maintained so that at a customer's point of supply the voltage is as set out in AS60038.

In addition, SA Power Networks, as a Registered Participant in the NEM, is required under clause 5.2.1(3) of the NER to maintain and operate all equipment that is part of its facilities in accordance with relevant Australian Standards, which would include AS60038.

8.17.2 SA Power Networks' Original Proposal

In our Original Proposal, we proposed a step change of $33.8 (June 2015, $ million) over the 2015-20 RCP to enable us to respond to these challenges. This included:

- additional customer and retailer engagement costs to assist with the introduction of new cost-reflective network tariff arrangements, to be phased in progressively during the 2015-20 RCP and then become mandatory for all new customers and customers upgrading their supply arrangements from 1 July 2017;
- additional communications and IT costs to upgrade our IT systems and develop new business processes to manage the transition to full competition in metering and the installation of smart meters; and
- additional communications and IT costs to support the progressive establishment of voltage monitoring across older areas of the LV network, making use of the capabilities of the more advanced meters required to support the new cost-reflective network tariffs.

Further detail was provided in Section 1.3.4 of Attachment 21.13 to the Original Proposal.

8.17.3 AER's Preliminary Determination

In its Preliminary Determination, the AER rejected our proposed step change because it was of the view that:

- our proposal to install more advanced meters in order to enable tariff reform was not prudent given the uncertainty surrounding the proposed transition to full competition in metering (and the likelihood that the retailer would be the first point of contact for the customer and only complex calls would be referred to SA Power Networks);
- SA Power Networks would incur some additional consultation costs in developing new tariff structures but that:
  - we had overestimated the additional expenditure in call centre staff associated with network tariff reform; and
  - our proposed approach to LV network monitoring was not possible as it relied on the capabilities of the more advanced meters we had proposed to install in the network and that the associated capital costs of 'smart-ready' meters had been rejected by the AER in its Preliminary Determination.

8.17.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks' proposed approach to metering was primarily driven by the need to introduce cost-reflective network tariffs, which require that customers have more advanced meters (also known as interval meters).

The draft Expanding Competition in Metering and Related Services Rule change was published on 26 March 2015. In that draft determination, the AEMC proposed that Type 4 meters be mandatory for all new customers and all customers upgrading their meters from July 2017. This contrasts with the 'opt in' approach to rolling out interval meters taken by the AEMC in an earlier consultation paper on the proposed Rule change. As a consequence, we now have greater confidence that a retailer-led smart meter rollout will enable new network tariffs to be introduced in the timeframe we require and we no longer need to install interval meters ourselves.

However, we will still incur ongoing and material increases in expenditure in complying with the new regulatory obligations imposed by the Distribution Network Pricing Arrangements and Expanding Competition in Metering and Related Services Rule changes that will be implemented during the 2015-20 RCP, and implement strategies to monitor compliance of the LV network to comply with the AS60038 Standard.

Transition to cost-reflective network tariffs

We remain committed to tariff reform, and have already introduced:

- a new residential monthly demand tariff in July 2014;
- a new business monthly demand tariff in July 2015; and
- our proposals to the AER in relation to new cost-reflective tariffs for solar PV customers from July 2015, among other measures (rejected by the AER).

As mentioned above, in its Preliminary Determination the AER acknowledged that we would incur additional costs in developing the new tariff structures required by the Distribution Network Pricing Arrangements Rule change. However, it did not accept our proposed expenditure because it had rejected our proposal to install more advanced meters and was of the view that we had overestimated the additional expenditure we forecast to incur in employing additional call centre staff to address the needs to the tariff reform.

Taking the AER's preliminary decision into consideration we have now revised our approach to tariff reform to place greater reliance on retailers, not only for the provision of interval metering but also in customer education and support. As a consequence of these changes our forecast step change in operating expenditure over the 2015-20 RCP in this area has reduced to $5.1 (June 2015, $ million). This comprises:

- an additional four FTEs commencing in 2017/18, dedicated to supporting small and medium businesses in the transition to cost-reflective pricing. The forecast cost for this is $1.9 (June 2015, $ million). The need for adequate support and education for small and medium businesses to help them to manage the transition to cost-reflective tariffs was highlighted by both Business SA[258] and the SA Wine Industry Association[259] in their submissions on our Original Proposal;
- production and distribution of education materials, including customer information packs, and the ongoing development and implementation of policies and procedures related to tariff reform. The forecast cost for this is $1.7 (June 2015, $ million); and
- additional customer support centre staff of $1.5 (June 2015, $ million), over the 2015-20 RCP, which is incrementally profiled on the basis of one FTE commencing in 2016/17 increasing to four FTEs in 2017/18 when cost reflective tariffs are launched.

[258] Business SA, *Submission on SA Power Networks' Regulatory Proposal 2015-20* , January 2015.
[259] SA Wine Industry, *Submission on SA Power Networks' Regulatory Proposal 2015-20*, January 2015.

Further details in relation to our revised strategy are set out in Attachment H.7: *Distribution Network Pricing Rules* to this Revised Proposal.

Introduction of full competition in metering

The changes affected by the Expanding Competition in Metering and Related Services Rule change when finalised will require us to implement new business processes and systems and increase staffing levels to manage the unprecedented mass replacement of SA Power Networks' regulated Type 6 meters with third party smart meters.

The forecast step change in operating expenditure over the 2015-20 RCP is $5.1 (June 2015, $ million) comprising:

- additional personnel (six to eight FTEs) to process meter 'transfers' where new smart meters are installed. The forecast cost of this is $2.6 (June 2015, $ million);
- IT systems support and maintenance costs and additional software licensing associated with expanded capacity of billing systems to manage the significantly increased volumes of metering data from four reads per customer per annum to 17,500 reads per customer per annum. The forecast cost of this is $1.1 (June 2015, $ million);
- additional resources to process higher volumes of interval data for network billing. The forecast cost of this is $1.0 (June 2015, $ million) and has been based on 0.5 FTE per 50,000 interval meters, based on the experience of Victorian distribution businesses; and
- an additional resource to co-ordinate commercial contracts and logistical arrangements with new Metering Coordinators. The forecast cost of this is $0.4 (June 2015, $ million).

Further details in relation to our revised strategy are provided in Attachment H.8 *SA Power Networks Competition in metering Rule change*.

Monitoring the LV network

As mentioned in our Original Proposal, because of the high (and increasing) levels of solar PV penetration predicted for the 2015-20 RCP, modelling suggest that SA Power Networks will be unable to meet its regulatory obligation to maintain supply voltage at customer premises within the range specified in AS60038.

As discussed in Section 7.12, we have obtained additional evidence since our Original Proposal was submitted that indicates widespread voltage issues are already emerging. Furthermore, the extent of these issues is significantly greater than revealed by the number of customer complaints we have received to date.

Given that third party smart meters will not be required to be rolled out under the new competitive metering framework until July 2017, we have developed a revised strategy to deal with these issues. This involves deploying a smaller number of grid-side monitoring devices to targeted areas during the 2015-20 RCP. This will enable us to defer expansion of more widespread monitoring until the 2020-25 RCP, by which time we expect to be able to access power quality data from the roll out of third party smart meters. Under this approach our forecast step change in operating expenditure over the 2015-20 RCP is significantly reduced relative to our Original Proposal to $3.0 (June 2015, $ million). This comprises:

- incremental IT costs for software licensing, support and maintenance and telecommunication costs (3G). The forecast cost of this is $1.3 (June 2015, $ million);

- additional back office and field staff (2 FTEs in total), and associated costs, to support, configure and maintain voltage monitoring devices. The forecast cost of this is $1.2 (June 2015, $ million); and
- a new resource (1 FTE) to manage and operate the voltage monitoring system, undertake analysis of data and liaise with other stakeholders within the business on LV voltage management. The forecast cost of this is $0.5 (June 2015, $ million).

Further details in relation to our revised strategy, and the evidence we have recently obtained in relation to the voltage issues emerging in our network, are provided in Attachment G.12: *SA Power Networks Voltage monitoring in the LV network*.

8.17.5 Revised Proposal

Our Revised Proposal includes a forecast for this step change of $13.2 (June 2015, $ million), as set out in Table 8.29.

This step change takes into account:

- the final Distribution Network Pricing Arrangements Rule change and the placing of greater reliance on retailers for the provision of customer education and support;
- the AEMC's draft determination in relation to the Expanding Competition in Metering and Related Services Rule change that is expected to be finalised in July 2015; and
- the approach to voltage monitoring of the LV network as described in Section 7.12.

Table 8.29: Demand side participation step changes SCS for the 2015-20 RCP (June 2015, $ million**)**

	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Distribution network pricing	0.0	1.0	1.3	1.4	1.4	**5.1**
Metering contestability	0.2	0.8	1.3	1.4	1.4	**5.1**
LV Network Monitoring	0.2	0.6	0.7	0.7	0.8	**3.0**
Demand Side Participation	**0.4**	**2.4**	**3.3**	**3.5**	**3.6**	**13.2**

8.18 Legal and Regulatory: Distribution licence fee

8.18.1 Rule requirements

Under the Electricity Act, SA Power Networks is required to hold a licence to operate the distribution network, and is charged an annual licence fee.

8.18.2 SA Power Networks' Original Proposal

On 11 September 2014, we were advised by the SA Minister for Mineral Resources and Energy that our annual licence fee would be reduced by $1.1 (June 2015, $ million) from 1 July 2015.

In our Original Proposal, we proposed that our operating expenditure base year be negatively adjusted by $1.1 (June 2015, $ million) to reflect this reduction.

Following the submission of our Original Proposal, we received advice from the Minister advising that the reduced fee would not apply until 11 October 2015. This was communicated to the AER prior to its Preliminary Determination.

8.18.3 AER's Preliminary Determination

The AER accepted the revised adjustment of $5.0 (June 2015, $ million) over the 2015-20 RCP, as it is directly related to the delivery of SA Power Networks' regulatory obligations. However, the AER proposed that this be included as a step change rather than an adjustment to our base year.

8.18.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks accepts the AER's preliminary decision.

8.18.5 Revised Proposal

Consistent with the information communicated to the AER after the submission of our Original Proposal and prior to the Preliminary Determination, our revised adjustment for the reduction in our distribution licence fee adjustment is $5.0 (June 2015, $ million), as set out in Table 8.30.

Table 8.30: Distribution licence fee step change SCS for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Distribution Licence Fee *	(0.7)	(1.1)	(1.1)	(1.1)	(1.1)	**(5.0)**

* Does not add due to rounding

8.19 Capital program impact: Information Technology

8.19.1 Rule requirements

We have a wide range of regulatory obligations in relation to the provision of SCS. We cannot discharge those obligations without appropriate information technology (**IT**) systems and practices.

8.19.2 SA Power Networks' Original Proposal

In our Original Proposal, we included a step change of $43.9 (net of forecast benefits of $21.2 million) (June 2015, $ million) on account of the additional operating expenditure required to support our proposed IT capital expenditure program.

Further detail concerning our proposed IT step change and IT capital expenditure was provided in Section 2.1 of Attachment 21.13 and Attachment 20.42 to the Original Proposal.

8.19.3 AER's Preliminary Determination

In its Preliminary Determination, the AER rejected all of the IT step changes arising from the IT capital program, citing the following underlying reasons for that decision:

- several proposals were aimed at achieving cost efficiencies, which would be expected to lead to lower operating expenditure rather than higher operating expenditure;
- several proposals were focussed on achieving compliance with existing regulatory obligations or requirements while other proposals referred to the need to comply with regulatory obligations or requirements that were not clearly identified;
- several proposals were related to replacement systems and/or software, which were assessed as not requiring additional operating expenditure;
- the AER's rate of change approach is designed to provide a business with incremental operating expenditure relating to business growth; and
- the need for increased funding for enterprise information security was not clear.

8.19.4 SA Power Networks' response to AER Preliminary Determination

We have reassessed the IT operating expenditure step changes related to our revised IT capital expenditure program and have only included four of the original IT step changes in our Revised Proposal. Those step changes are described below.

In relation to each remaining step change, we have considered the applicability of the AER's reasons for rejecting the step change and have explained why those reasons do not justify the rejection of the revised step change.

Data Centre Consolidation

In its Preliminary Determination, the AER states that the Data Centre operating expenditure step change will be compensated through the rate of change adjustment. The AER cites this as the reason for not approving the $4.5 (June 2015, $ million) operating expenditure step change.

It is clear from this reasoning that the AER assumed that the increase in the volume of data required to be collected by SA Power Networks as a result of various recent (eg the AEMC's Distribution Network

Pricing Arrangements Rule change) and imminent (eg the AEMC's Expanding Competition in Metering and Related Services Rule change) changes to regulatory obligations, was the only driver for the step change.

However, this is incorrect. This step change and the related data centre consolidation project is actually an efficient capex/opex trade-off which was inadequately described in the Original Proposal.

We have therefore resubmitted the operating expenditure step change of $4.5 (June 2015, $ million) as an efficient capex/opex tradeoff.

The proposed data centre step change is required to support the cost to host SA Power Networks' current IT applications and data in purpose built facilities managed by a specialist data centre service provider. This approach is a change to the current data centre arrangements and was the preferred option in the IT capital expenditure Business Case included in Attachment S20.102 to our Original Proposal.

SA Power Networks' current data centre facilities have reached capacity, in terms of both physical space and data processing capacity. The current disaster recovery and business continuity capabilities are also inadequate and therefore SA Power Networks has re-evaluated this business risk from high to extreme in accordance with its corporate risk management policy.

SA Power Networks has decided to change to an outsourced arrangement as it is the most efficient and prudent way for us to manage these risks. In implementing this arrangement, SA Power Networks will incur a material and ongoing increase in operating expenditure as a result of its decision to host SA Power Networks' current IT applications and data in purpose built facilities, managed by a specialist data centre service provider.

The alternative option would be to undertake a capital project to increase SA Power Networks in-house data centre capability. As noted in the IT capital expenditure Business Case provided in Attachment S20.102 of our Original Proposal, this option is not the most efficient solution to mitigate the business continuity risks of the in-house facilities to meet our increased data storage needs. Switching to an outsourced arrangement was the most efficient option.

The Data Centre Business Case has been updated to provide further detail of the operating costs associated with the new facilities arrangement. See Attachment G.13: *IT Data Centre Business Case*.

Enterprise Information Security Foundation

The Enterprise Information Security Foundation Business Case included in Attachment S20.102 of our Original Proposal provided general information concerning our current information security capabilities and future requirements. In its Preliminary Determination, the AER expressed the view that the evidence contained within the Business Case was insufficient to justify an increase in forecast operating expenditure.

We consider that we provided the AER with clear evidence concerning the risks facing SA Power Networks within our Original Proposal. Nevertheless, our resubmission of an operating expenditure step change of $9.0 (June 2015, $ million) is supported by additional information relating to the increasing cyber security threats, the latest information on industry changes and expectations, changes to the SA Power Networks environment and our approach to mitigating risks. See Attachment G.17: *Enterprise Information Security Business Case*.

In particular, the amended Business Case provides details concerning each of the issues listed by the AER on page 7-93 of the Preliminary Determination.

SA Power Networks believes that this information demonstrates that it needs a material and ongoing increase in its total forecast operating expenditure in order to properly implement and support the associated IT capital expenditure to manage information security.

The specific security risks faced by SA Power Networks are:

- Information Technology Risks – unauthorised access to the corporate IT environment by an external or internal party resulting in SA Power Networks' corporate systems and data being compromised. The consequences of such a breach has the potential to:
  - interrupt customer facing services or lead to a loss of data resulting in non-compliance with our regulatory obligations;
  - lead to unauthorised disclosure of private and sensitive information held by SA Networks in relation to our customers, staff and contractors, resulting in non-compliance with regulatory obligations; and
  - lead to disclosure of corporate information to unauthorised parties, resulting in increased vulnerabilities to future attacks and financial consequences;
- Operational Technology (**OT**) Risks – unauthorised access to the OT environment by an external or internal party resulting in SA Power Networks' electricity distribution system and related data being compromised. The consequences of such a breach include the potential to cause:
  - power outages;
  - damage to our network; and
  - potential loss of life; and
- Supply Chain Risks – unauthorised access to either the corporate or operational environments via a third party supplier, whose network or equipment has been compromised which could have any of the above consequences. This risk will increase as we require further information to be provided to us by our suppliers under our RIN obligations (eg via our Vegetation Management contract requirements).

These risks are expected to increase in the 2015-20 RCP due to:

- increased terrorist and cyber-criminal activity as evidenced from recent industry and government reports;[260]
- convergence between IT, OT and Telecommunications (**Tel**) environments due to the recent implementation of the Advanced Distribution Management System (**ADMS**). Evidence exists of escalating cyber security issues related to the IT/OT/Tel convergence;[261]
- greater number of external suppliers that are allowed access to the IT/OT/Tel network; and
- greater variety of devices and applications used on the network, for example, the use of mobile applications and personal IT devices such as tablets or iPhones.

As a provider of an essential service and critical infrastructure, SA Power Networks has the responsibility to ensure that its distribution system is secure and able to continue to deliver a reliable supply of electricity to consumers during a cyber-attack or security breach. To do this, SA Power Networks needs to be able to detect such an attack, determine the method of attack, and mitigate the effects of the attack so that it is able to promptly restore the supply of electricity to consumers.

---

[260] Refer to, for example: Symantec, *Targeted Attacks Against the Energy Sector*, 1 January 2014, US Department of Homeland, *Security Status Report,* 1 June 2013; Price Waterhouse Coopers, *The Global State of Information Security Survey* 2015.

[261] Refer to, for example, Experts warn of escalating grid security issues after PG&E break-in, June 2015, http://www.utilitydive.com/news/experts-warn-of-escalating-grid-security-issues-after-pge-break-in/400524/.

In its Preliminary Determination, the AER states that its approach to assessing operating expenditure step changes considers, amongst other factors that '*Step Changes should generally relate to a new obligation or some change in the service providers operating environment beyond its control*.'[262] The proposed operating expenditure step change relates to changes in SA Power Networks operating environment (ie increased levels of cyber-security risks) which is beyond its control as they are driven by unavoidable changes in the external environment (ie increasing levels of terrorist and cyber-criminal activities).

The proposed operating expenditure step change is required to operate and maintain the new Information Security Management System that will be delivered as one of the key outcomes of the information security capital program and to perform ongoing security monitoring, threat management, vulnerability management, security awareness and identity management activities.

The size of SA Power Networks' information security team is lower than the utilities sector average. The proposed step change will bring the team more in line with our industry counterparts although our ratio will still remain lower than the industry average.

SAP Foundations

SA Power Networks' SAP hardware platform (which includes an Oracle database system and a User Interface for the Enterprise Resource Planning (**ERP**) system) requires a major technical upgrade during 2015/16.

The system was originally implemented in 1997 and apart from incremental upgrades every five years the database technology has remained largely untouched. This foundational technology platform poses an extreme risk to our business as we expect to reach maximum capacity in late 2015, based on the trajectory of current needs, and before consideration of significant forecast increases in data. Our current database technology (Oracle) is effectively reaching the end of its technical life and is limiting the functional development of the SAP ERP.

As part of the upgrade, we are changing to the vendor recommended database to ensure we can continue to leverage our ERP into the future. This is in line with accepted industry practices which have been adopted by other organisations which have a corporate SAP ERP and are driven by:

- the AEMC's Distribution Network Pricing Arrangements Rule change and the AEMC's Expanding Competition in Metering and Related Services Rule change that will require us to manage a larger number of market participants, more complex business processes and to collect an increased volume of interval data from smart meters; and
- the increased information to be collected and reported to the AER in accordance with the Economic Benchmarking (**EB**) and Category Analysis (**CA**) RINs.

In relation to the increase in actual (as compared to estimated) data that we must now collect and report to the AER in accordance with the EB and CA RINs, we note that we have addressed the AER's incorrect assumptions concerning the work involved in collecting and storing this data in Section 8.15 of this chapter. In particular, the AER has misunderstood the step change in the level of work required to collect and store actual data across the wide range of granular asset and work categories now required by the AER.

---

[262] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 7-72.

This step change upgrade means net increases in operating expenditure costs for software maintenance as well as marginal increases in labour costs. The AER rejected this step change because it formed the view that an increase in total operating expenditure is not required for a step change that relates to replacement systems and software. This assumption is incorrect, as can be demonstrated by comparing the recurrent operating costs of the current platforms versus the proposed platforms.

The underlying capital project will lay a durable and reliable foundation on which our long term future technology operating environment will be built.

The Business Case for this project has been updated since our Original Proposal and can be found in Attachment G.19: *SAP Foundations Business Case*. The updated Business Case discusses in detail the external and internal drivers of the required change and the associated revised costs.

CISOV replacement system

SA Power Networks needs an appropriate billing and customer related system in order to meet its regulatory obligations and requirements and maintain its ability to:

- generate network bills;
- collect and process meter data;
- manage service orders;
- manage meter assets;
- manage customer and property information;
- analyse and report on 'interval' meter data (that will increase in volume over the 2015-20 RCP as smart meters are rolled out as a result of the AEMC's Expanding Competition in Metering and Related Services Rule change);
- support our regulatory reporting obligations; and
- respond to market changes.

In its Preliminary Determination, the AER made provision for our proposed CISOV (billing system) replacement project in its alternative IT capital expenditure forecast but rejected our proposed step change for the associated operating expenditure step change. This decision was based on the AER not being satisfied that replacement of systems and software require an increase in total operating expenditure as costs to support systems would change year to year and should be covered by the base year.

SA Power Networks' IT vendor has indicated that it is unable to support the existing systems past 2021; therefore the systems will need to be replaced in the 2015-20 RCP. The current billing and customer related system is a legacy system based on CIS OV (Customer Information System) and CRM (Customer Relationship Management) technology. These systems are at end of life and comprise technology that is ageing, disparate and does not provide the flexibility required to support the provision of proactive, responsive and reliable service to meet customers' needs now and in the future.

In a situation of 'like for like' upgrades, significant increases in operating expenditure might not be expected. However, in this instance, current and planned regulatory changes (including the AEMC's Distribution Network Pricing Arrangements Rule change and the AEMC's Expanding Competition in Metering and Related Services Rule change) are driving requirements for new capabilities. To respond to these changes effectively, SA Power Networks requires a new technical foundation capability in order for it to comply with its regulatory obligations and interact with more complex business and market environments. This capability will require additional support and maintenance.

The AER's assumption that the additional support, maintenance and licensing costs associated with the CISOV replacement system will be covered by the base year is incorrect. The proposed CISOV replacement system has associated licensing costs that are significantly higher than the minimal licensing costs associated with SA Power Networks' current legacy billing system.

The additional costs associated with the CISOV replacement system are a material and ongoing efficient cost that SA Power Networks will incur in the 2015-20 RCP and beyond. This reflects the fact that the existing solution was largely developed in-house over a long period of time (9 out of 10 applications). Therefore SA Power Networks has not had to pay associated software maintenance costs for a number of systems which form part of the current CIS OV and CRM environment.

The original Business Case for this project has been updated since our Original Proposal and can be found in Attachment G.21: *CISOV Replacement Business Case*. The Business Case discusses in detail why our legacy billing and customer related system needs to be replaced in the 2015-20 RCP, the replacement options we considered, why the CISOV replacement system was selected as the preferred option, and the material and ongoing costs that are associated with this new system.

8.19.5 Revised Proposal

Our Revised Proposal for this step change is $19.4 (June 2015, $ million), set out in Table 8.31.

Table 8.31: Revised Information technology step changes SCS for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Data Centre	1.2	0.9	0.8	0.8	0.8	**4.5**
Enterprise Security	1.3	1.8	1.9	2.0	2.0	**9.0**
SAP Foundation	0.3	0.5	0.5	0.5	0.5	**2.3**
CISOV	0.0	0.0	1.2	1.2	1.2	**3.6**
Total	**2.8**	**3.2**	**4.4**	**4.5**	**4.5**	**19.4**

8.20 Capital program impact: Mobile Radio

8.20.1 Rule requirements

The mobile radio network is essential to our operations and for managing the provision of SCS, including planned works, switching and customer connections.

The mobile radio network is also essential for compliance with our regulatory obligations, including supply restoration to meet ESCoSA service standards, and maintaining the safety of the distribution system (eg to enable us to respond to storm damage, vehicle accidents and bushfire events).

As an essential service provider we cannot rely solely on a commercial third party carrier's network (such as mobile phone networks), as these often become unavailable during wide spread supply interruption events.

8.20.2 SA Power Networks' Original Proposal

The migration of our mobile radio network capacity to the South Australian Government Radio Network (**SAGRN**) was assessed as the most prudent and efficient solution for replacing our existing mobile radio network which has exceeded its equipment life expectancy. The migration to the new system and decommissioning of the old system will occur in 2016/17.

In our Original Proposal, we proposed a step change, incremental to the 2010-15 RCP maintenance cost, for the expenditure required to effect this migration. The forecast for this step change was $7.8 (June 2015, $ million).

8.20.3 AER's Preliminary Determination

In its Preliminary Determination, the AER accepted our proposed step change on the basis that it represents an efficient capex/opex trade-off. The AER's preliminary decision is contingent upon the finalisation of the supporting business case.

8.20.4 SA Power Networks; response to AER Preliminary Determination

Negotiations have continued with the South Australian Government in respect of the cost and timing of migrating to the new SAGRN. Whilst a final agreement has not yet been reached, the details exchanged to-date confirm the cost-benefit parameters, and the migration still remains the preferred and least cost option.

Our Telecommunications Mobile Radio Network business case has been updated since our Original Proposal and can be found in Attachment H.9: *SA Power Networks Radio Network Business Case*. That business case discusses in detail the available options including the upgrade of the existing SA Power Networks Radio Network, use of mobile phones and the migration to the SAGRN.

As the AER acknowledged in its preliminary decision there is a clear need to address this gap in our infrastructure.

8.20.5 Revised Proposal

Our Revised Proposal includes a forecast for this step change of $12.8 (June 2015, $ million). A table showing the cash flow has not been provided due to confidentiality reasons.

This Revised Proposal takes into account the South Australian Government's updated letter of offer to SA Power Networks to migrate, with a commencement date of December 2016. This includes an initial one-off payment, which was incorrectly classified as capital expenditure in the Original Proposal, plus a recurrent annual fee.

The one-off payment operating expenditure component accounts for the difference between the Original Proposal and Revised Proposal amounts, as explained in Attachment H.9: *SA Power Networks Radio Network Business Case*.

8.21 Capital program impact: Non network solution

8.21.1 Rule requirements

As part of the Better Regulation program, the AER published a regulatory investment test for distribution (**RIT-D**) in 2013.

The RIT-D commenced operation on 1 January 2014 and replaced the previous process in South Australia that was governed by ESCoSA under ESCoSA Electricity Guideline No 12. The RIT-D test is used to determine the ‘best’ upgrade solution, be it a network or non-network solution, from an end customer perspective.

8.21.2 SA Power Networks’ Original Proposal

The Bordertown non-network solution was assessed under the ESCoSA Electricity Guideline No 12 process and was implemented in 2013. This solution has deferred, until at least September 2020, approximately $26 million in capital expenditure works relating to the requirement to upgrade the Bordertown substation, Keith to Bordertown 33kV line and Keith 132/33kV Transmission Connection Point.

The incremental costs associated with the ongoing generation standby capacity and operational fees of the non-network solution are forecast to be on average $0.3 million per annum higher than the 2013/14 base year costs of $0.3 million.

In our Original Proposal, we proposed that our operating expenditure base year be adjusted by $1.3 (June 2015, $ million) over the 2015-20 RCP to reflect this increase.

8.21.3 AER’s Preliminary Determination

The AER formed the view that this increase in expenditure was a step change, as opposed to a base year adjustment, and in doing so rejected it on the basis that its approach is to forecast total operating expenditure and not forecast operating expenditure at the category level.

8.21.4 SA Power Networks’ response to AER Preliminary Determination

We reject the AER’s preliminary decision in relation to this step change and resubmit it as part of this Revised Proposal.

In implementing the Bordertown non-network solution, SA Power Networks went through an extensive public consultation process where the options for reinforcing supply to Bordertown to meet the forecast increase in demand were considered. The public process, which was similar to the AER's RIT-D assessment process, determined that the most cost-effective solution was for SA Power Networks to enter into a network support agreement with a third party generator.

SA Power Networks (then ETSA Utilities) signed a contract with a third party supplier which entails payments until 2021. Those network support payments increase annually based on the annual forecast demand at the time the contract was signed.

This constitutes an ongoing and material increase in costs that is required in order for SA Power Networks to carry out this non-network solution, and which was approved in accordance with the regulatory process in force at the time, namely following the South Australian equivalent to the AER's RIT-D assessment process.

We also remind the AER of its analogous arrangements for Transmission Network Service Providers (**TNSPs**), noting that the network support payments for the Bordertown non-network solution are similar to network support payments made by a TNSP to a Generator or other person instead of augmenting a transmission network. Such arrangements are subject to a pass through event under the NER that is defined as a network payment support event, with a zero materiality threshold.

If the AER does not approve our proposed increase in operating expenditure to account for the increases in expenditure required to make the increased network support payments for the Bordertown non-network solution, DNSPs can have no confidence in the AER's RIT-D evaluation approach where that evaluation results in a third party solution. This will place a significant disincentive on DNSPs to employ demand management solutions because under the AER's approach, as evidenced by this preliminary decision, a DNSP will need to seek a fixed price for this type of network support, which by definition will be higher and most likely include a significant contingency on account of the risk of any change in cost over the term of the network support arrangement. This will increase the cost of non-network solutions and ultimately the cost to consumers. It will also place non-network demand management options at a competitive disadvantage to network augmentation options.

This outcome is clearly inconsistent with the NEO – it will result in a less efficient outcome for consumers forcing DNSP's to seek fixed price non-network solutions, creating a bias towards network solutions.

As discussed earlier in this chapter, the argument that the AER provides funding for total operating expenditure and not individual programs or projects as justification of the rejection of this step change is not valid. This increase in cost is not reflected in our efficient base year operating expenditure. It represents a material and on-going increase in the total operating expenditure required to achieve the operating expenditure objectives as compared to our efficient base year operating expenditure.

8.21.5 Revised Proposal

Consistent with our Original Proposal, our Revised Proposal includes the incremental costs relating to the ongoing generation standby capacity and operational fees associated with the Bordertown non-network solution is $1.3 (June 2015, $ million) over the 2015-20 RCP. A table showing the cash flow has not been provided for confidentiality reasons.

8.22 Capital program impact: Data quality

8.22.1 Rule requirements

We have a wide range of regulatory obligations which require us to translate the vast volumes of data that we collect into accurate and meaningful information and knowledge that can be used for decision-making, national market operations and service delivery. We cannot discharge these obligations without appropriate data quality systems.

We cannot discharge these obligations and provide customer services without appropriate data quality systems.

The Data Management Association (**DAMA**) provides a globally accepted framework and good practice reference for data management. The definition of data management provided in the DAMA Data Management Body of Knowledge is *'Data management is the development, execution and supervision of plans, policies, programs and practices that control, protect, deliver and enhance the value of data and information assets.'*

Furthermore, in assessing the expenditure required to comply with all of these obligations, SA Power Networks is required to have regard to *'the extent to which the forecast includes expenditure to address the concerns of electricity consumers identified by the DNSP in the course of its engagement with electricity consumers'*[263] (**Consumer Engagement Factor**).

8.22.2 SA Power Networks' Original Proposal

The commencement of Full Retail Contestability in 2003 created a large repository of customer information, new business processes and data exchange obligations for SA Power Networks to manage. Over time it has become evident that there are shortcomings in our data that have affected (and will continue to affect) the outcome of business processes, and ultimately the customer service provided to South Australians and our ability to comply with our regulatory obligations.

Throughout the 2010-15 RCP, we completed a series of data improvement initiatives in relation to a subset of data issues. During this time our reliance on the quality of customer data has also increased as a result of the implementation of new systems and business processes. Issues with the quality of our customer data are now much more critical to our daily operations.

Our 2015-20 Customer Data Quality Plan, which follows our work over the 2010-15 RCP, has been developed to address the issues with customer data that we are still experiencing. This involves moving to holistic data management system, building on the investment we have made to date in people and technology. It will also add new capabilities for data cleansing and enrichment, and increase coverage to all components of the customer data domain.

Our *2015-20 Customer Data Quality Plan* was provided to the AER as Attachment 16.1 to the Original Proposal.

The proposed step change for implementing this program is $3.9 (June 2015, $ million).

Further detail is provided in Section 2.3 of Attachment 21.13 to the Original Proposal.

[263] Clause 6.5.6(e)(5A) of the NER.

8.22.3 AER's Preliminary Determination

In its Preliminary Determination, the AER rejected this step change on the basis that improvements associated with the data quality program (if efficient) should result in lower, not higher, operating expenditure.

As an example, the AER highlighted that, in SA Power Networks business case, SA Power Networks noted that problems with data quality can lead to potentially incorrect decisions which may lead to increased maintenance costs and outages, and administrative overheads to correct the issue. If the cost associated with data errors and correcting those errors is greater than the cost associated with new data management systems designed to correct those errors, then the AER formed the view that it would expect SA Power Networks' operating expenditure to be lower as a result of its data quality program. As such the AER was not convinced that a higher operating expenditure forecast is needed.

8.22.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks does not accept the AER's preliminary decision to reject this step change and has included this step change in this Revised Proposal.

In the Original Proposal, we may not have adequately explained the relationship between the Customer Data Quality Plan and the provision of accurate data in accordance with our regulatory obligations.

SA Power Networks has an obligation to provide accurate information to the National Electricity Market, as detailed in the Australian Energy Market Operator (**AEMO**) Market Settlement and Transfer Solutions (**MSATS**) Procedures: Consumer Administration and Transfer Solution (**CATS**) Procedures, Principles and Obligations.[264] Specifically, Section 2.2(i) of those MSATS Procedures provides that *'CATS Participants must ensure, as required under specific obligations within the CATS Procedures, that all new and existing standing data in MSATS is kept current and relevant, for the National Metering Identifier (**NMIs**) they are responsible for.*' Further, under section 2.4(t), a Local Network Service Provider, such as SA Power Networks, must *'[c]onsider and action as necessary within two business days any requests from incorrectly assigned Participants.'*

A failure to comply with MSATS Procedures is a breach of the NER as detailed under clause 7.2.8 'Market Settlement and Transfer Solutions Procedures' of the NER.

Inadequate data quality is a pervasive industry wide issue, particularly with respect to the customer transfer process between retailers. The Australian Energy Market Commission (**AEMC**) published a report on its 'Review of Electricity Customer Switching' in April 2014. In that report, the AEMC made recommendations as to improving the accuracy of the customer transfer process, which included the development of standards (including an address standard) to be applied by market participants, for data that is used in the customer transfer process.

Whilst improvements to customer data have been made during the 2010-15 RCP, SA Power Networks still has approximately 150,000 incorrect property addresses. This inaccurate data impacts on the provision of the delivery of SCS and can result in our regulatory obligations not being met. For example, under clause 90(1) of the National Energy Retail Rules (**NERR**), SA Power Networks must, as a DNSP, notify all affected customers of a planned interruption at least four days before the date of interruption. There is also a specific critical provision for customers who rely on life support equipment under clause 125 of the NERR, highlighting the utmost importance of DNSPs having

[264] AEMO, MSATS Procedures: *CATS Procedures Principles and Obligations*, Version 4.1, 1 July 2014.

accurate customer information in order to contact and advise affected customers of planned interruptions.

Furthermore, increased data quality obligations continue to arise under various regulatory change processes. This includes the ongoing AEMC Power of Choice reform program that has created a significant number of data quality issues that must be addressed. For example, in section 2.7 of its 'Power of Choice – Proposed Work Program' document (May 2015), AEMO outlines the first phase of its work in response to the Council of Australian Governments (**COAG**) requirement to address the cleansing of NMI standing data and the review of the effectiveness of MSATS Procedures with regard to objections and other relevant matters.

These obligations, associated with customer data, are aligned to clause 6.5.6(a) of the NER, with particular reference to the second objective to 'comply with all applicable regulatory obligations or requirements associated with the provision of SCS.'

In addition to our regulatory obligations, customers concerns, as identified through our comprehensive CEP, have been pivotal in the development of our Customer Service Strategy 2014-2020 (**CSS**). The CSS, which has significant data quality implications, reflects our customers' demands for a range of customer information improvements. For example, customers have made it clear that:

- they are not all the same, and while there is a basic common service, they do have differing needs and expectations for other services must be catered for;
- they want more choice in the channels by which they interact with us; and
- they increasingly value self-service technologies and access to information and services wherever they are.

Accordingly, our CSS includes key initiatives that are designed to:

- further develop self-service options that our customers value;
- increase the use of social media, mobile and email to communicate with our customers;
- strengthen the data collection and information flows from our field personnel to our customers to provide accurate and timely information on service status and power restoration activities;
- implement a Customer Relationship Management (**CRM**) business system which provides a single view of the customer and enables the service to be tailored to be responsive to their immediate and future needs; and
- continue to develop the multiple communication channels that customers now expect.

The provision of accurate and timely data is pivotal to achieving these initiatives. For this reason, our Customer Data Quality Plan is a key enabler for the delivery of our CSS and has been developed to address the issues with customer data that we are still experiencing. The focus of the plan is to specifically improve customer data in areas such as:

- communicating with our customers;
- locating our assets and customers to correctly map customer addresses (ie aligned to the regulatory requirements discussed above);
- managing the connectivity of customers to the distribution network; and
- providing information between the field and office.

To ensure that our data quality can meet our regulatory obligations and requirements as well as these operational requirements in the 2015-20 RCP, we are proposing to moderately increase resourcing levels, initially by 11 Full Time Equivalents (**FTEs**) and then reducing to 7 FTEs in the latter half of the 2015-20 RCP. The benefits arising from this program are driven by SA Power Networks' requirement to meet our regulatory obligations and requirements as well as our customers' requirements, as opposed to the AER's conclusion that this program is driven by, and will lead to, reduced operating expenditure.

In preparing our Original Proposal and this Revised Proposal, we have been guided by the National Electricity Objective and the Consumer Engagement Factor which require us to act in the long term interests of consumers.

8.22.5 Revised Proposal

Consistent with the Original Proposal our Revised Proposal includes a forecast for this step change of $3.9 (June 2015, $ million), as set out in Table 8.32.

Table 8.32: Data quality step change SCS for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Data Quality	1.0	0.8	0.7	0.7	0.7	**3.9**

8.23 Customer driven: Vegetation management

8.23.1 Rule requirements

SA Power Networks is required by section 55 of the Electricity Act to take reasonable steps to keep vegetation of all kinds clear of power lines in accordance with the principles of vegetation clearance set out in the *Electricity (Principles of Vegetation Clearance) Regulations 1996* (SA) (**Vegetation Clearance Regulations**). These principles establish a mandatory and prescriptive program for vegetation clearance in both bushfire and non-bushfire risk areas. For example regulation 4 of the Vegetation Clearance Regulations requires inspection and clearance cycles to be carried out at least every three years.

This duty to take reasonable steps requires us to have regard to an objectively determined standard.

This standard will, by definition, change over time as what constitutes reasonable steps is influenced by industry developments and learnings <u>and by the expectations and requirements of electricity consumers.</u>

Furthermore, in assessing the expenditure required to comply with all these obligations, the AER is required to have regard to:

> *'the extent to which the forecast includes expenditure to address the concerns of electricity consumers identified by the DNSP in the course of its engagement with electricity consumers'* [265] (**Consumer Engagement Factor**).

8.23.2 SA Power Networks' Original Proposal

As outlined in the Original Proposal, SA Power Networks has responded to a clear mandate arising from our CEP for action to be taken in the 2015-20 RCP to shift away from our 'one size fits all' tree trimming strategy to a more sustainable long term vegetation management strategy.

The development of this long term approach has been undertaken in a highly collaborative manner with strong support from the Local Government Association (**LGA**) and our independent Arborist Reference Group. It is also supported by our extensive research and consultation with consumers on tree trimming that has shown there is a willingness to pay (**WTP**) for enhancing longer term vegetation management approaches across the State.

In our Original Proposal, we submitted that the following step changes be included to address the concerns of our consumers:

- moving to a more frequent two year trimming cycle in metropolitan Adelaide and regional townships, forecast at $13.5 (June 2015, $ million);
- undertaking tree removal and replacement programs in Bushfire Risk Areas (**BFRAs**) and Non Bushfire Risk Areas (**NBFRAs**) to remove inappropriate, fast growing or large trees, forecast at a net cost of $9.2 (June 2015, $ million) in BFRAs and $6.1 (June 2015, $ million) in NBFRAs;
- engaging arborists to provide expert advice and input into advanced tree trimming practices, forecast at $1.9 (June 2015, $ million); and
- enhancing community engagement and consultation in support of the long term vegetation management strategy, forecast at $1.2 (June 2015, $ million).

---

[265] Clause 6.5.6(e)(5A) of the NER.

Further detail was provided in Section 3.1 of Attachment 21.13 to the Original Proposal.

8.23.3 AER's Preliminary Determination

The AER rejected these step changes because it formed the view that:

- improved amenity is not an objective the AER is directed to consider when determining funding requirements, that being a broader policy issue that goes beyond the AER's remit;
- SA Power Networks' WTP research does not provide persuasive evidence that SA Power Networks' consumers support the programs;
- there are already other sources of funding available other than regulated electricity revenues, including provision for local councils to assist SA Power Networks in funding vegetation management programs by signing up to Vegetation Clearance Agreements with SA Power Networks under the Electricity Act;
- SA Power Networks' base year opex should already provide a sufficient source of funding for it to address safety and bushfire risks; and
- the programs are expected to deliver cost savings and the AER does not approve increases in funding for programs that expect to deliver efficiencies.

8.23.4 SA Power Networks' response to AER Preliminary Determination

In making its Final Determination, the AER is required to make a decision that will contribute to the achievement of the National Electricity Objective,[266] which is:

> *'to promote investment in, and efficient operation and use of, electricity services for the long term interests of consumers with respect to –*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.'*[267]

As set out above, the AER is also required to have regard to the Consumer Engagement Factor.[268]

In preparing our Original Proposal and this Revised Proposal, we have been guided by the Consumer Engagement Factor and the National Electricity Objective that require us to act in the long term interests of consumers when making decisions.

The vegetation management activities we propose to undertake in the 2015-20 RCP are driven by these obligations and will result in us incurring a material and ongoing increase in expenditure during the 2015-20 RCP.

Against that background, we address below the specific issues raised by the AER in its preliminary decision in relation to these step changes.

[266] Section 16(1) of the NEL.
[267] Section 7 of the NEL.
[268] Clause 6.5.6(e)(5A) of the NER.

Improved Amenity

SA Power Networks' building block proposal must include expenditure to comply with our regulatory obligations and (to the extent that there is no applicable regulatory obligation or requirement) to maintain the quality of supply of standard control services.

As recognised by the AEMC in the 2012 Rule change, addressing customer preferences for improved amenity can amount to maintaining the quality of supply and should be taken into account by the AER when having regard to the Consumer Engagement Factor:

> *'In respect of [the Consumer Engagement Factor] which will allow for the AER to have regard to the extent to which NSPs have considered what consumers seek, there are various ways this could be relevant. For example, it may be the case that a majority of affected consumers are unhappy with the visual impact of a proposed new line. If the NSP engages with consumers, it may decide that the best way to address the concerns of consumers would be to build the line underground, even if this is a more expensive option. When the AER considers the NSP's overall capex proposal, it should take into account that the proposed option will provide a higher quality of service in line with consumers' preferences and willingness to pay, above less expensive options which fall below the level of service demanded by customers. In general, a NSP that has engaged with consumers and taken into account what they seek could reasonably expect the AER to take a more favourable view of its proposal.'*[269] *[emphasis added]*

In addition, the AEMC has recognised that what consumers want and are prepared to pay for assists in determining what is efficient and this may result in a program being warranted even if it is not the least cost option.[270]

Given these observations by the 'rule maker', we consider that the AER has misinterpreted the third objective in clause 6.5.6(a) of the NER and has erred in rejecting these step change proposals based on the view that improved amenity is not an objective the AER is directed to consider when determining funding requirements. Expenditure to address concerns about amenity can and does fall within the reach of the third objective.

We recognise that the expenditure objective relating to maintaining the quality of supply was amended by the AEMC in the 2013 Rule change. In that Rule change, the AEMC did not expressly refer to questions of amenity in its description of quality. However, in the context of the issues being addressed in that Rule change, we think it is clear that the AEMC did not mean to contradict its earlier comments concerning the quality and amenity.

As set out in Chapter 3 of this Revised Proposal, SA Power Networks' comprehensive CEP is representative of electricity consumers and of the community in South Australia. It has clearly demonstrated widespread support for a shift from the current three year inspection and cutting cycle to a shorter cycle in metropolitan areas and rural townships, in order to allow more frequent tree trimming to be undertaken in areas where high value is placed on street trees and visual amenity. This is further supported by the outcomes from our targeted WTP research which has shown there is a willingness to pay for enhancing longer term vegetation management approaches across the State.

---

[269] AEMC, *Economic Regulation of Network Service Providers,* Final Rule Determination, 29 November 2012, page 115.
[270] AEMC, *Economic Regulation of Network Service Providers,* Final Rule Determination, 29 November 2012, page 101.

Willingness to Pay

As outlined in the Original Proposal and in Chapter 3 of this Revised Proposal, we engaged The NTF Group (as one aspect of our extensive CEP) to undertake targeted WTP research to test whether the community would support our proposed vegetation management activities. The WTP research confirmed that our customers are willing to pay for the following vegetation management activities:

- a shift from a three to a two year trimming cycle in NBFRAs; and
- tree removal and replacement programs in both BFRAs and NBFRAs.

As discussed in Section 3.4 of this Revised Proposal, the AER's inaccurate conclusions about the validity of our CEP findings, and the WTP research in particular, have led it to reject these customer driven initiatives.

These step changes must now be reassessed by the AER by reference, and by giving considerable weight, to the Consumer Engagement Factor. To appropriately 'have regard' to these concerns the AER must treat that factor as a fundamental element of its decision.[271] The AER cannot simply note that such concerns have been identified and discard them.[272] It must treat the consideration of these concerns (and the extent to which forecast expenditure addresses them) as a central element of its decision.[273]

Local Council partnerships

SA Power Networks has undertaken extensive consultation with local councils, who represent approximately 1.3 million South Australian consumers, to understand their expectations in relation to vegetation management initiatives. This has included running two local government forums, presentations to Regional Council Groups and individual Councils and establishing a LGA Working Group.

With respect to funding of vegetation management initiatives, SA Power Networks is aware that there is provision in section 55A of the Electricity Act for local councils to assist SA Power Networks in funding vegetation management programs by entering into vegetation clearance schemes with us. However, in practice, local councils have not been prepared to do so or have only done so on a very limited basis.

Councils have limited resources and manage a significant number of street trees and council reserves. Having said that, SA Power Networks has, over the last 12 months, undertaken a number of tree removal trials in NBFRAs and BFRAs in partnership with Councils. Councils have generally contributed to these trials by undertaking one of the activities involved with the process, such as community consultation and stump removal.

In this context, in terms of economic and resource efficiency, Councils are well placed to engage with the community given their existing relationships, whereas SA Power Networks is better placed to remove trees. Tree removals also provide a long-term economic benefit to consumers and avoid the continual pruning of trees that require ongoing clearance. The NBFRA and BFRA tree removal and replacement program costing is limited to those costs that SA Power Networks will incur as a result of those activities (eg SA Power Networks does not pay for costs associated with stump removal).

---

[271] *R Hunt; ex parte Sean Investments Pty Ltd* [1979] 180 CLR 332 at 329; *R v Toohey; ex parte Meneling Station Pty Ltd* [1982] HCA 69, per Gibbs CJ at [5], per Mason J at [13]; *Re Michael; ex parte Epic Energy (WA) Nominees Pty Ltd* [2002] WASCA 231 at [55]; *Telstra Corporation Limited v ACCC* [2008] FCA 1758 at [105]; *Telstra Corporation Limited v Australian Competition Tribunal* [2009] FCAFC 23 at [267]; *Re Application by EnergyAustralia* [2009] ACompT 7 at [16].
[272] *East Australian Pipeline Pty Ltd v ACCC* [2007] HCA 44 at [52].
[273] *Telstra v ACCC* [2008] FCA 1758 at [52].

SA Power Networks is of the view that it is not reasonable to wait until Councils are willing to enter into funding arrangements under the Electricity Act in relation to vegetation management. If that was the position taken by SA Power Networks, the significant concerns of consumers in relation to visual amenity and safety aspects of vegetation management may well never be addressed and it is not appropriate for SA Power Networks to simply say that it is someone else's responsibility given that it clearly has obligations to appropriately maintain vegetation around power lines.

Proposed operating expenditure is a prudent and efficient investment

The forecast operating expenditure for our proposed vegetation management activities reflects the efficient and prudent costs of maintaining the reliability, safety and quality of electricity supply demanded by our consumers and complying with our applicable regulatory obligations.

Where vegetation exists below or in close proximity to power lines the risk of a reduction in reliability, safety and quality of electricity supply increases.

The relationship between these factors and fire start risks is discussed in further detail in Attachment H.10: *GHD Vegetation Management Bushfire Program*.

Our proposed vegetation management activities complement our bushfire mitigation program in that they comprise the targeted removal of trees based on high risk locations, vegetation density, species, flammability and volume of fuel load.

However, this step change stands alone from our bushfire mitigation program and the expenditure to be incurred in implementing that program is not a sufficient source of funding to address the safety and fire risks arising from our vegetation management practices.

Attachment H.10 discusses the proposed tree removal and replacement program incorporating the removal of saplings. The report highlights two significant problems:

- the first problem is the accumulation of legacy trees that are now in, or are entering, senescence (ie over-mature and decaying), and the emergent cohort of ‘problem’ trees that has resulted, in significant part, from the trend in recent decades to plant trees, particularly near power lines. This has created a situation which is a step up from that addressed by SA Power Networks' historical, clearance-compliance focussed program. We must therefore address this problem in order to maintain the safety, reliability and quality of electricity supply from our distribution system; and
- there has been, and will continue to be, an increase in the scale of sapling emergence because of the uncommonly experienced ‘pulse regeneration’ event which has followed the 2010/11 record rainfall period. If saplings are not removed through a targeted, systematic program, then safety, reliability and fire risk will increase across substantial areas of our network. Accordingly, SA Power Networks must implement a sapling removal program to maintain the safety, reliability and quality of electricity supply from its distribution system.

As set out above, in undertaking these vegetation management activities SA Power Networks will face material and ongoing increases in costs and the AER must, in making its Final Determination, have regard to those costs in giving SA Power Networks a reasonable opportunity to recover at least the efficient costs it incurs in complying with its regulatory obligations in a manner that addresses the concerns of consumers.

While it may be true that an efficient DNSP should - to some extent - be able to adopt new business practices without increasing overall levels of expenditure, this assumption does not address the scenario where an efficient firm is facing real increases in its cost inputs, or the need for material and on-going increases in expenditure in order to meet demand, satisfy customer expectations, or comply with regulatory obligations. As recognised by the AER, SA Power Networks is an efficient business and so cannot simply 'find the money elsewhere'. For us to meet these material and ongoing cost increases over the 2015-20 RCP, we would have to curtail other things we have been doing – works which, by definition, are prudent and efficient. An expenditure allowance that forces us, as an efficient DNSP, into this position, is not one that complies with the operating expenditure criteria.

In relation to our tree removal and replacement programs in BFRAs, we note that Oakley Greenwood's alternative WTP approach supported the selection of a program based on 2.5% of infringing spans. This supports the finding that our proposed operating expenditure is a prudent and efficient investment.[274]

Delivering efficiencies

The AER's view that the programs are expected to deliver cost savings and the AER does not approve increases in funding for programs that expect to deliver efficiencies, does not recognise the fact that cost savings may only arise over the longer term.

For example, the implementation of our tree removal and replacement program on its own, may well lead to some cost saving over the long term but, given the significant upfront costs of removing and replacing trees, the cost saving will not be realised in the 2015-20 RCP. The forecast cost of tree removal and replacement programs is $16.6 (June 2015, $ million) over the next five year period and is net of reduced cutting costs of $10.5 (June 2015, $ million).

There is also a further aspect of 'efficiency' that the AER fails to address. The AER appears to only turn its mind to questions of 'productive efficiency'. This is only one aspect of economic efficiency. Economic efficiency also includes allocative efficiency. The AER fails to address issues of 'allocative efficiency'. As a result, the AER fails to consider projects that provide broader benefits to consumers (ie over and above the regulated requirements) and are therefore efficient from an allocative efficiency perspective.

If consumers are willing to pay for enhanced services, then it is not efficient for a DNSP to be refused sufficient funding to deliver those services. In other words, it will be inefficient when customers want to buy a better level of service from the DNSP, and the DNSP is willing to provide that better level of service to prevent that from occurring. The AER’s failure to consider allocative efficiency prevents this potential 'transaction' between the DNSP and consumers, and it is consumers that lose out as a result.

In the case of our proposed vegetation management programs, which have been driven by consumers' significant concerns about safety and amenity expressed during our robust Consumer Engagement Program (CEP), there is evidence of consumers' willingness to pay for those programs. This evidence supports the allocative efficiency of these programs. To ignore this evidence would be contrary to the National Electricity Objective to 'promote efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity'.

8.23.5 Revised Proposal

Our Revised Proposal includes a forecast for these steps changes of $33.2 (June 2015, $ million), as set out in Table 8.33.

This Revised Proposal is $1.3 million higher than the Original Proposal as the BFRA tree removal and replacement program now excludes the $1.3 million saving associated with the Original Proposal

[274] Oakley Greenwood, *Peer review of the willingness to pay research submitted by SA Power Networks*, 20 April 2015, page 12.

program for undergrounding 135 km of line in BFRAs, that does not form part of this Revised Proposal (refer to Section 7.7 for further explanation).

Table 8.33: Revised vegetation management step changes SCS for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
NBFRA two year cycle	2.7	2.7	2.7	2.7	2.7	**13.5**
BFRA tree removal and replacement (net of savings)	3.1	2.6	2.1	1.6	1.1	**10.5**
NBFRA tree removal and replacement (net of savings)	1.7	1.4	1.2	1.0	0.8	**6.1**
Community engagement and consultation	0.4	0.4	0.4	0.4	0.4	**1.9**
Arborists	0.2	0.2	0.2	0.2	0.2	**1.2**
Vegetation management*	**8.1**	**7.3**	**6.6**	**5.9**	**5.2**	**33.2**

* Does not add due to rounding

8.24 Customer driven: Customer service

8.24.1 Rule requirements

Section 3.19 of our Safety, Reliability, Maintenance and Technical Management Plan (**SRMTMP**) requires us to raise awareness of the risks and obligations which are attendant with our electricity infrastructure, the use of electricity and the role of SA Power Networks in that process. It also includes a list of certain areas where the awareness of the general public needs to be raised but states that this list is simply an indication of some of the areas in which SA Power Networks provides information to raise the public's awareness as SA Power Networks is required to respond as needs or perceived needs arise.

SA Power Networks is required, under the conditions of its Distribution Licence and section 25 of the Electricity Act, to comply with its SRMTMP, which is approved by ESCoSA.

In addition, we have a number of regulatory obligations in relation to the provision of SCS that we cannot fully comply with without addressing customer service needs. For example, during the 2015-20 RCP, a number of important changes will occur in the industry, including the changes to cost-reflective tariffs now required by the AEMC's Distribution Network Pricing Arrangements Rule change and the introduction of full competition in metering following the making of the AEMC's Expanding Competition in Metering and Related Services Rule change in July 2015.

Furthermore, in assessing the expenditure required to comply with all of these obligations, the AER is required to have regard to:

> *'the extent to which the forecast includes expenditure to address the concerns of electricity consumers identified by the DNSP in the course of its engagement with electricity consumers'* [275] *(***Consumer Engagement Factor***).*

8.24.2 SA Power Networks' Original Proposal

As outlined in the Original Proposal, we have established our Customer Service Strategy 2014–2020 (**CSS**). This has been developed to align with key insights from market research, employee engagement, and customer engagement (including several workshops with residential, business, government, and other community stakeholders in Adelaide and regional areas) to ensure our direction reflects current, and anticipated future, customer values.

Consistent with the CSS, a number of key initiatives have been further developed during 2014/15 and will be progressively implemented during the 2015-20 RCP.

In our Original Proposal, we proposed that the following step changes be included in order to implement CSS initiatives:

- a program to educate customers on the electricity industry, forecast at $1.7 (June 2015, $ million), so that they better understand who we are and what we do;
- implementing a tailored digital advertising strategy, forecast at $1.0 (June 2015, $ million), to support the launch and communication of new self-service options and provide materials to various public and community groups; and
- introducing for the first time, a dedicated customer experience improvement team, forecast at $1.6 (June 2015, $ million). Members of this team will have the responsibility for developing

[275] Clause 6.5.6(e)(5A) of the NER.

customer service capability across the organisation and for ensuring priority customer improvement initiatives are deployed in the field across the organisation.

Further detail is provided in Section 3.2 of Attachment 21.13 to the Original Proposal.

8.24.3 AER's Preliminary Determination

In its Preliminary Determination, the AER rejected our proposed step changes because it was of the view that:

- the proposed step changes related to discretionary activities and discretionary expenditure should be managed within a service providers' existing budget;
- the AER needs clear and robust evidence about why a service provider needs more funding to achieve the objectives in order to provide a step change and SA Power Networks did not demonstrate this in relation to any of these programs; and
- it is not SA Power Networks' role to educate consumers about the electricity industry.

8.24.4 SA Power Networks' response to AER Preliminary Determination

As mentioned earlier in this chapter, in making its Final Determination for the purposes of our 2015-20 RCP, the AER is required to make a decision that will contribute to the achievement of the National Electricity Objective,[276] which is:

> *'to promote investment in, and efficient operation and use of, electricity services for the long term interests of consumers with respect to –*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.'*[277]

As set out above, the AER is also required to have regard to Consumer Engagement Factor.

In preparing our Original Proposal and this Revised Proposal, we have been guided by the Consumer Engagement Factor and the National Electricity Objective that require us to act in the long term interests of consumers.

We also have a clear regulatory obligation to raise awareness of the risks and obligations which are attendant with our electricity infrastructure, the use of electricity and the role of SA Power Networks in that process. This is an important obligation, as the electricity industry is changing and evolving, particularly with the introduction of new technologies which impact on service delivery and safety, and impending rule changes (such as the Expanding Competition in Metering and Related Services Rule change).

Against that background, we address below the specific issues raised by the AER in its preliminary decision in relation to these step changes.

We have a regulatory obligation under Section 3.19 of our SRMTMP to raise awareness about the role of SA Power Networks in the electricity industry. Compliance with regulatory obligations is not discretionary.

---

[276] Section 16(1) of the NEL.
[277] Section 7 of the NEL.

In addition, consumers have overwhelmingly indicated, through our CEP (which is representative of electricity consumers and of the community in South Australia) that they want more information about SA Power Networks and the services we provide.

In order to ensure that we continue to comply with this obligation under our SRMTMP, meet the expressed needs of consumers and manage the operating environment that is continually changing around us, it is imperative that we improve our communication and service delivery with customers. In order to do this, we need to build on our CEP, support the use of multi-channel forms of service and communication, and deliver our new CSS, which is directed at meeting emerging customer needs, including to:

- proactively seek opportunities to make a positive connection with communities and business across metropolitan and rural South Australia;
- deliver customer service that is tailored and responsive to immediate and changing needs; and
- be a trusted source of advice and information for customers' current and future electricity needs.

The supporting key initiatives outlined in Section 8.24.2 above will ensure that we can meet our obligations under the SRMTMP, meet and manage demand for standard control services and address the concerns of our customers (as required by the NER).

As outlined in Section 8.11, and discussed in detail in Attachment H.11: *NERA Funding Projects that Provide Customer Benefits* to this Revised Proposal, rejecting these customer driven step changes on the basis that they are discretionary will create inefficiency, because without these programs we will not be meeting the long term interests of customers.

For these reasons the proposed customer service step changes are required to meet our regulatory obligations, are both prudent and efficient, and are in accordance with the operating expenditure objectives.

8.24.5 Revised Proposal

Our Revised Proposal includes forecasts for these steps changes of $4.3 (June 2015, $ million), as set out in Table 8.34.

Table 8.34: Revised customer driven step changes SCS for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Customer education and consultation	0.6	0.0	0.5	0.1	0.5	**1.7**
Customer service	0.0	0.4	0.4	0.4	0.4	**1.6**
Self-service products	0.4	0.3	0.1	0.1	0.1	**1.0**
Customer Service	**1.0**	**0.7**	**1.0**	**0.6**	**1.0**	**4.3**

8.25 Customer driven: Community safety

8.25.1 Rule requirements

Section 3.19 of our Safety, Reliability, Maintenance and Technical Management Plan (**SRMTMP**) requires us to raise awareness of the risks and obligations which are attendant with our electricity infrastructure, the use of electricity and the role of SA Power Networks in that process. It also includes a list of certain areas where the awareness of the general public needs to be raised but states that this list is simply an indication of some of the areas in which SA Power Networks provides information to raise the public's awareness.

SA Power Networks is required, under the conditions of its Distribution Licence and section 25 of the Electricity Act, to comply with its SRMTMP, which is approved by ESCOSA.

In addition, under section 60(1) of the Electricity Act SA Power Networks has a duty to take reasonable steps to ensure that our distribution system is safe and safely operated and to maintain our facilities in accordance with good electricity industry practice. This obligation is supplemented by SA Power Networks' obligation under clause 5.2.1(a) of the NER and parallels its duty of care under the common law of negligence.

A number of factors inform the current meaning of the obligation to take reasonable steps to ensure our distribution system is safe and safely operated.

Furthermore, in assessing the expenditure required to comply with all of these obligations, the AER is required to have regard to:

> *'the extent to which the forecast includes expenditure to address the concerns of electricity consumers identified by the DNSP in the course of its engagement with electricity consumers'* (**Consumer Engagement Factor**).

8.25.2 SA Power Networks' Original Proposal

As outlined in the Original Proposal, we have established a Communications Plan 2014–2020. The plan contains a comprehensive, but prudent, advertising and support program to address a significant number of the consumer insights generated from our CEP.

The new initiatives contained in the plan which address safety, are based on consumer feedback, and align with our safety obligations under the Electricity Act.

In our Original Proposal, we proposed that the following step changes be included to implement these initiatives:

- **Bushfire** - summer time media campaign to better educate our customers about the dangers and implications of potential bushfire events, as well as having better coverage during high risk bushfire days in respect to power lines and outages;
- **Extreme weather** - broad media campaign, targeted in the months prone to severe weather events, to better educate our customers about the dangers and implications of extreme weather outages and fallen power lines; and
- **Farmers and sailors** - an extension of the current program, delivered through multiple media channels, to ensure that this group is adequately informed as to the safety risks arising from power line hazards as they pertain to agricultural equipment and sailing boat masts.

The total forecast cost of these step changes is $5.4 (June 2015, $ million).

Further detail is provided in Section 3.3 of Attachment 21.13 to the Original Proposal.

8.25.3 AER's Preliminary Determination

The AER rejected these step changes because it was of the view that:

- the proposed step changes related to discretionary activities and discretionary expenditure should be managed within a service providers' existing budget;
- the AER needs clear and robust evidence about why a service provider needs more funding to achieve the objectives in order to provide a step change and SA Power Networks did not demonstrate this in relation to any of these programs; and
- public safety should and would always be a priority for SA Power Networks but what matters in determining a total operating expenditure forecast is whether the total operating expenditure SA Power Networks spends on public safety needs to increase. SA Power Networks did not provide any compelling evidence that any of the programs necessitate a total increase in funding activities directed towards public safety.

8.25.4 SA Power Networks' response to AER Preliminary Determination

As mentioned earlier in this chapter, in making its Final Determination for the purposes of our 2015-20 RCP, the AER is required to make a decision that will contribute to the achievement of the National Electricity Objective,[278] which is:

> *'to promote investment in, and efficient operation and use of, electricity services for the long term interests of consumers with respect to –*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.'*[279]

As set out above, the AER is also required to have regard to the Consumer Engagement Factor.

In preparing our Original Proposal and this Revised Proposal, we have been guided by the Consumer Engagement Factor and the National Electricity Objective and which require us to act in the long term interests of consumers.

We also have a duty to take reasonable steps to ensure that our distribution system is safe and safely operated and to maintain our facilities in accordance with good electricity industry practice and a specific regulatory obligation to raise awareness of the risks and obligations which are attendant with our electricity infrastructure, the use of electricity and the role of SA Power Networks in that process.

Against that background, we address below the specific issues raised by the AER in its preliminary decision in relation to these step changes.

We have a regulatory obligation under Section 3.19 of our SRMTMP to raise the public's awareness of the risks that are inherent in our electricity infrastructure, which would include the general risks that arise in relation to bushfires and extreme weather events and specific risks that affect certain

[278] Section 16(1) of the NEL.
[279] Section 7 of the NEL.

consumer groups, such as farmers and sailors. Compliance with regulatory obligations is not discretionary.

As set out in Chapter 3 of this Revised Proposal, SA Power Networks' comprehensive CEP is representative of electricity consumers and of the community in South Australia. It has clearly demonstrated that consumers value safety very highly and want (and expect) us to undertake additional steps and programs of work to ensure ongoing community safety. This extends to better communication in relation to three specific areas of safety - bushfires, extreme weather and farmers and sailors.

Failing to implement these communication programs to address these safety risks does not align with what our consumers have demonstrated (through our CEP) that they want and would result in a non-compliance with Section 3.19 of our SRMTMP.

Moreover, these programs are consistent with the operating expenditure objectives, in particular the second and fourth objectives of complying with regulatory obligations and requirements, and maintaining the safety of the distribution system. This was highlighted by the AER in its comments in our 2010 Draft Determination that:

> *'The AER considers that some level of community engagement expenditure directly related to the safe provision of electricity distribution services to the public may be reasonably attributed to SCS, for example, advertising campaigns that promote public safety awareness and notification of proposed works which may impact on it's customers' use of the distribution network. The AER considers that such expenditure is likely to be consistent with the operating expenditure objectives, in particular, clauses 6.5.6 (2), (3) and (4) of the NER.'*[280]

Further, our duty to take reasonable steps to ensure that our distribution system is safe and safely operated is informed by good electricity industry practice in Australia. It is good electricity industry practice for DNSPs to implement safety communication programs for the benefit of their consumers. For example, bushfire safety is very prominent in the communication activities of DNSPs such as ActewAGL in the ACT, Endeavour Energy and Essential Energy in NSW, Energex in Queensland, and SP AusNet, United Energy Distribution and Powercor in Victoria.

At this point in time, we are out of step with what constitutes good electricity industry practice because we have not yet implemented the specific initiatives set out in this step change and we must implement those initiatives in order to continue to comply with our regulatory obligations.

As acknowledged by the AER, public safety should be, and is, a priority for SA Power Networks. However, in implementing the initiatives outlined above (which initiatives SA Power Networks has not carried out in the past), we will incur a material and ongoing increase in expenditure. This expenditure was not included in our base year.

8.25.5 Revised Proposal

Consistent with the Original Proposal, the Revised Proposal includes forecasts for these steps changes of \$5.4 (June 2015, \$ million), as set out in Table 8.35.

[280] AER, *Final Decision: South Australia distribution determination 2010-11 to 2014-15,* May 2010, page 225.

Table 8.35: Revised community safety step changes SCS for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Bushfire communications	0.7	0.5	0.4	0.6	0.4	**2.6**
Extreme weather	0.6	0.5	0.3	0.2	0.3	**1.9**
Farmers and sailors	0.3	0.1	0.2	0.1	0.2	**0.9**
Community safety	**1.6**	**1.1**	**0.9**	**0.9**	**0.9**	**5.4**

8.26 Revised Proposal

Our revised SCS operating expenditure forecast is $1,421.9 (June 2015, $ million) and is summarised in the table 8.36.

This combined with debt raising costs of $10.1 (June 2015, $ million) and DMIA costs of $3.0 (June 2015, $ million) results in a total operating cost of $1,435.0 (June 2015, $ million).

Table 8.36: Revised Proposal SCS operating expenditure costs for the 2015-20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Adjusted Base year	239.1	239.1	239.1	239.1	239.1	**1,195.3**
Rate of Change	5.4	10.8	16.9	23.4	30.1	**86.6**
Step Changes	25.3	31.2	28.9	28.3	26.3	**140.0**
Opex Forecast	**269.8**	**281.0**	**284.8**	**290.8**	**295.5**	**1,421.9**
Debt Raising	1.9	1.9	2.0	2.1	2.2	**10.1**
DMIA	0.6	0.6	0.6	0.6	0.6	**3.0**
Total (incl debt raising & DMIA)*	**272.2**	**283.6**	**287.5**	**293.5**	**298.2**	**1,435.0**

* Does not add due to rounding

9. Pass-through events

9.1 Rule requirements

Clause 6.6.1(a1) of the NER provides that a pass through event for a distribution determination is any of the following:

(1) a ‘regulatory change event’;

(2) a ‘service standard event’;

(3) a ‘tax change event’;

(4) a ‘retailer insolvency event’; and

(5) any other event specified in a distribution determination as a pass through event for the determination.

Under clause 6.5.10(a) of the NER, SA Power Networks is permitted to propose additional pass through events for inclusion under clause 6.6.1(a1)(5) having regard to the ‘nominated pass through event considerations’.

The nominated pass through event considerations are:

(a) whether the event proposed is an event covered by a category of ‘pass through event’ specified in clause 6.6.1(a1)(1) to (4) of the NER;

(b) whether the nature or type of event can be clearly identified at the time the determination is made for the service provider;

(c) whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;

(d) whether the relevant service provider could insure against the event, having regard to:

  (1) the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or

  (2) whether the event can be self-insured on the basis that:

    (i) it is possible to calculate the self-insurance premium; and

    (ii) the potential cost to the relevant service provider would not have a significant impact on the service provider’s ability to provide network services; and

(e) any other matter the AER considers relevant and which the AER has notified NSPs is a nominated pass through event consideration.

9.2 SA Power Networks’ Original Proposal

SA Power Networks proposed the following additional nominated pass through events in its Original Proposal:

- Kangaroo Island cable failure event;
- natural disaster event;
- insurer credit risk event;

- liability above insurance cap event;
- native title event; and
- general nominated pass through event.

All of these additional pass through events have previously been accepted by the AER either in SA Power Networks' or other DNSPs' determinations, except for the Kangaroo Island cable failure event which was previously considered by SA Power Networks to be captured under the general nominated pass through event.

Each of the additional nominated pass through events were proposed on the basis that they met all of the nominated pass through event considerations described in Section 9.1 above (including that there is a real risk that they could not be cost effectively covered by insurance).

9.3 AER's Preliminary Determination

In its Preliminary Determination, the AER accepted three of our proposed pass through events but amended the definitions of those events, and rejected the other three events.

The three pass through events that were accepted after being amended were:

- natural disaster event;
- liability above insurance cap event (which the AER renamed as an 'insurance cap event'); and
- insurer credit risk event.

The three pass through events that were rejected by the AER were:

- general nominated pass through event;
- Kangaroo Island cable failure event; and
- native title event.

Each of the six proposed pass through events is addressed briefly below.

9.3.1 Natural disaster event

The AER accepted that a natural disaster event is consistent with the nominated pass through event considerations.[281] However, the AER amended the proposed definition to:[282]

- insert a list of matters to which the AER will have regard when assessing a pass though application in respect of such an event; and
- remove the term 'storm' from our proposed definition.

The AER's proposed definition of a natural disaster event is as follows:

'A natural disaster event occurs if:

[281] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 15-13.
[282] Ibid.

Any major fire, flood, earthquake or other natural disaster occurs during the 2015-20 regulatory control period and materially increases the costs to SA Power Networks in providing direct control services, provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider.

The term 'major' in the above paragraph means an event that is serious and significant. It does not mean material as that term is defined in the Rules (that is 1 per cent of the distributor's annual revenue requirement for that regulatory year).

Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:

i. whether SA Power Networks has insurance against the event,

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event, and

iii. whether a relevant government authority has made a declaration that a natural disaster has occurred.'

9.3.2 Liability above insurance cap event or insurance cap event

The AER accepted that a liability above insurance cap event is consistent with the nominated pass through considerations.[283] However, the AER amended the proposed definition to:[284]

- include a modified list of matters to which the AER will have regard when assessing a pass through application in respect of such an event; and
- change the name of the event to align it with other recent distribution determinations by the AER (The AER now refers to this type of type of event as an 'insurance cap event').

The AER's proposed definition for an insurance cap event is as follows:

'An insurance cap event occurs if:

1. SA Power Networks makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy,

2. SA Power Networks incurs costs beyond the relevant policy limit, and

3. the costs beyond the relevant policy limit materially increase the costs to SA Power Networks in providing direct control services

For this insurance cap event:

4. the relevant policy limit is the greater of:

a. SA Power Networks actual policy limit at the time of the event that gives, or would have given rise to a claim, and

b. the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the regulatory control period in which the insurance policy is issued.

[283] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 15-11.
[284] Ibid.

5. *A relevant insurance policy is an insurance policy held during the 2015-20 regulatory control period or a previous regulatory control period in which SA Power Networks was regulated.*

Note for the avoidance of doubt, in assessing an insurance cap event cost pass through application under rule 6.6.1(j) the AER will have regard to:

i. the relevant insurance policy for the event, and

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of that event.'

9.3.3 Insurer credit risk event

The AER accepted that an insurer credit risk event is consistent with the nominated pass through event considerations. [285] However, the AER amended the proposed definition to:[286]

- insert a list of matters to which the AER will have regard when assessing a pass through application in respect of such an event; and
- remove the pass through of costs associated with material changes to insurance premiums as a result of an insurer becoming insolvent.

The AER's proposed definition for an insurer's credit risk event is as follows:

'An insurer's credit risk event occurs if:

A nominated insurer of SA Power Networks becomes insolvent, and as a result, in respect of an existing or potential insurance claim for a risk that was insured by the insolvent insurer, SA Power Networks:

1. is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or

2. incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.

Note: In assessing an insurer's credit risk event pass through application, the AER will have regard to, amongst other things,

i. SA Power Networks' attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation.

ii. In the event that a claim would have been made after the insurance provider became insolvent, whether SA Power Networks had reasonable opportunity to insure the risk with a different provider.'

9.3.4 General nominated pass through event

The AER rejected the general nominated pass through event because: [287]

- the AER's view was that the event could not be clearly identified at the time that the Preliminary Determination was made;
- the AER's assessment was that it could not be satisfied that SA Power Networks was unable to insure against the event or reliably measure the steps it had taken to explore alternative risk management options; and

---

[285] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 15-15.
[286] Ibid.
[287] Ibid.

- the AER had rejected proposed general nominated pass through events in recent decisions.

9.3.5 Kangaroo Island cable failure event

The AER rejected the Kangaroo Island cable failure event because the AER formed the view that a prudent service provider could reasonably prevent the event from occurring.[288]

9.3.6 Native title event

The AER rejected the native title event because the AER formed the view that SA Power Networks was in a position to mitigate the costs of the event occurring.[289]

9.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks:

- accepts the AER's decision that each of the following events is a nominated pass through event:
  - natural disaster event;
  - insurance cap event (previously named 'liability above insurance cap event'); and
  - insurer credit risk event; but
- has amended the AER's proposed definition of natural disaster event to expressly include significant weather as classified by the Bureau of Meteorology (**BoM**), remove the word 'major' and remove the definition of 'major'; and
- has revised the definitions of all three events to remove the references to assessment criteria, as these should not form part of the pass through event definitions.

SA Power Networks:

- does not agree with the AER's assessment that our proposed Kangaroo Island cable failure event is not a pass through event, and we therefore maintain our position that this event should be approved by the AER; and
- proposes that a terrorism event be approved as an additional pass through event (given that such an event would, in our view, have been captured under the general nominated pass through event rejected by the AER).

Each of these matters is addressed below.

9.4.1 Assessment factors

Before turning to the specific pass through events, we address generally the issue of the inclusion by the AER of assessment factors within pass through event definitions.

In our view, it is not appropriate or legally valid to include assessment factors within pass through event definitions. Assessment factors do not relate to how a nominated event should be assessed by the AER under clause 6.5.10 of the NER. Instead, such factors relate to a completely different aspect of a pass through event, namely, whether an application by a DNSP to pass through a positive (or negative) pass through amount after a particular category of approved pass through event has actually occurred, should be approved by the AER or not (by applying clauses 6.6.1(d) or 6.6.1(g) of the NER).

---

[288] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 15-17.
[289] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, page 15-18.

Nominated pass through events do need to be defined clearly so there is sufficient clarity at the outset as to the nature of an event that will be eligible for consideration for a pass through by the AER. Then, once such an event occurs, the pass through application and assessment process can be activated. There is no automatic right to pass through to customers an amount just because a defined event has occurred; whether that will eventuate or not depends, first, on a DNSP actually making a pass through application and, secondly, if it does, the AER then determining that an amount should in fact be passed through after applying the factors set out in clause 6.6.1(j) of the NER. It is at this second step that assessment factors are relevant – not prior to that step. By including assessment factors within definitions, the AER appears to be seeking to augment (or expand upon) the regulatory regime set down by the NER. We contend that doing this is both inappropriate and legally invalid, as the AER is not the rule maker. Furthermore, as there are no assessment factors to be found within the definitions in the NER of the four 'pre-defined' pass through events, the actions of the AER in incorporating assessment factors into proposed nominated pass through events is inconsistent with the intentions of the NER and the rule maker, the AEMC.

In our Original Proposal, we did include reference to assessment factors in one of our proposed pass through events, namely for the liability above insurance cap event. This was done at the time because, for consistency reasons, we adopted wording that had been approved by the AER in previous determinations. However, having given the matter further consideration, and obtained legal advice on the issue, we do not consider that assessment factors should be included in any of the nominated pass through event definitions.

9.4.2 Natural disaster event

The AER accepted our nomination of a natural disaster event and, as noted above, we accept that decision. However, the AER made amendments to our proposed definition that we do not accept.

Storm

The AER removed the reference to 'storm' from the definition. Its only reason for doing so was that *'the term 'storm' is not sufficiently clear so as to indicate when such a pass through would apply'*[290]. We do not agree with the AER view that 'storm' is not a sufficiently clear event, however given the AER's desire for greater specificity, we propose to change the term 'storm' to 'significant weather'.

The BoM – being an independent, expert meteorological (weather) body - provides a section within its monthly weather review which is titled 'significant weather' which includes thunder storms, strong winds, cyclones etc. 'Significant weather' includes a range of weather related events which are, by definition, beyond the control of SA Power Networks and are therefore very clear examples of occurrences which fall within the ambit of paragraph (c) of the definition of nominated pass through event considerations. Significant weather includes a range of weather related events. We therefore propose that the term 'significant weather' be included in the definition.

Proviso

In its amended definition of 'natural disaster event', the AER included the qualification '*provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider'.* We consider that this proviso is not required. The proviso is effectively restating clause 6.6.1(j)(3) of the NER which, being a factor that the AER must take into account if and when an application to pass through an amount is made, states:

---

[290] AER, *Preliminary Decision: SA Power Networks determination 2015−16 to 2019−20*, Attachment 15 − Pass through events 15.4.3 page 15-14.

'(3) *in the case of a positive change event, the efficiency of the Distribution Network Service Provider's decisions and actions in relation to the risk of the positive change event, including whether the Distribution Network Service Provider has failed to take any action that could reasonably be taken to reduce the magnitude of the eligible pass through amount in respect of that positive change event and whether the Distribution Network Service Provider has taken or omitted to take any action where such action or omission has increased the magnitude of the amount in respect of that positive change event;'*

It may be entirely appropriate to reduce a pass through amount because of the actions or omissions of SA Power Networks. But that does not mean that a natural disaster event has not occurred. The latter is a definitional issue; the former goes to the quantum (if any) of the pass through amount.

'Major'

In our Original Proposal, we included the word 'major' as part of the definition of 'natural disaster event'. On further reflection, that word is inappropriate, creates confusion and uncertainty, and should not be included for the reasons discussed below.

In its Preliminary Determination, the AER included a definition for the word 'major' in its definition of 'natural disaster event'. The definition of 'major' should not be included.

Whether a natural event is major or minor is not relevant to the definition (or categorisation) of such an event. A natural event will either have occurred, or not. The occurrence of the natural event – being something which is clearly beyond the control of SA Power Networks – should essentially be the primary determinant of whether a pass through event has occurred. If it has, then SA Power Networks should be entitled to make an application to pass through an amount to customers. It will be at the point that an application (if any) is made, that the question of 'major' or 'minor' will be relevant, although that question will be determined (as required by the NER) by whether the cost of the event has exceeded the materiality threshold of one percent of revenue, or not. If it has then it will be material (or, colloquially, 'major'). If it has not, then it will not be material (or, colloquially, 'minor' or not 'major') and there will be no pass through to customers.

The AER proposes that the word 'major' be defined to mean *'an event that is serious and significant. It does not mean material as that term is defined in the Rules (that is 1 per cent of the distributor's annual revenue requirement for that regulatory year)*'. That suggests that the AER is seeking to impose a 'double materiality' threshold; something which the NER neither contemplates nor permits given that rule making is the role of the AEMC, not the AER. This wording could lead to the AER arguing that an event was not 'major' because it considers the event not to have been 'serious or significant' despite the fact that the costs of the event may have exceeded the one percent materiality threshold. Yet that would be contrary to the clear wording and intention of the NER.

If that is not the intention of the AER in including the definition of 'major', then there is no work for that definition to do.

Either way, the word 'major' and the definition of that word clearly should not appear in the definition of 'natural disaster event'.

We note the following examples as a reminder of how the pass through provisions of the NER work and how they allocate cost impacts as between SA Power Networks and its customers:

- SA Power Networks has not experienced a significant weather event in recent history where the cost of the event would have exceeded the one percent of revenue materiality threshold. Accordingly, SA Power Networks has borne the costs of those events as there was no ability to seek to pass through the costs to customers; and
- South Australia experienced a major bushfire called the Sampson Flat bushfire last summer which burnt more than 20,000 hectares, burnt out 27 homes, 140 out buildings and resulted in 134 injuries. It was declared a state emergency, but not a natural disaster, by the State Government. The total cost of the bushfire was estimated at $13 million, but the cost to SA Power Networks was less than the one percent threshold.

In other words, the one percent threshold by itself makes any natural disaster 'major' without any additional definitions, qualifiers or provisos being required. All that adding such things in, is cloud the consistency, transparency, predictability and certainty that otherwise exists for SA Power Networks, the AER and its customers in relation to how the pass through provisions are to be applied during a RCP.

Assessment factors – general and specific

In accepting a natural disaster event as a pass through event the AER also included, within the definition, factors that it will take into account when it assesses a pass through application for that event. We addressed generally, in Section 9.4.1 above, why the inclusion of such factors is inappropriate in the definition of any pass through event. We therefore propose that no such factors be included.

In addition to those general reasons, we also specifically do not support the AER's proposed inclusion of the factor '*whether a relevant government authority has made a declaration that a natural disaster has occurred*'. We have no control whatsoever over whether a government authority will, or will not, choose to make such a declaration. Whether such a declaration is made or not is not the issue. The issue is whether the event was beyond our control and, if so, whether it materially increases the costs of SA Power Networks in providing direct control services. The answers to those questions do not change just because a government authority does, or does not, make a declaration.

State and Territory Governments are responsible for declaring whether an event is a natural disaster. When a State Government declares a natural disaster it is focused on the impacts on its citizens (eg damage to houses, injuries, etc), not on the impact to network businesses. The government has its own criteria for determining whether an event is a natural disaster or not. For example, the NSW Government declared a natural disaster in 12 local council areas associated with a severe storm and flooding on 20 April 2015 which caused significant damage to homes and other property. This damage was not significantly different to the damage caused by the Sampson Flat bushfire referred to above which was not declared as a natural disaster by the SA Government. Yet both events should be eligible for a pass through of costs provided the costs exceed the one percent materiality threshold – regardless of whether one is declared as a natural disaster and the other is not.

As highlighted above, the one percent materiality threshold is (and should be) the only threshold relevant to determining whether an event has had a significant impact on a DNSP, and consequently no additional criteria can be legitimately applied in order for a DNSP to be eligible for a potential pass through of costs as a result of a natural disaster event. And again, we note that costs cannot be passed through to customers unless the AER, after assessing the relevant factors as detailed in clause 6.6.1(j) of the NER, approves the amount of the costs that are to be passed through to customers.

We therefore propose that no assessment factors (including whether a natural disaster has been declared) be included in the definition of natural disaster event.

9.4.3 Insurance cap event

The AER accepted our nomination of an insurance cap event (previously labelled by us as 'liability above insurance cap event') and, as noted above, we accept that decision.

However, in accepting an insurance cap event as a pass through event the AER included, within the definition of that event, factors that it will take into account when it assesses a pass through application. We addressed generally, in Section 9.4.1 above, why the inclusion of such factors is inappropriate in the definition of any pass through event. We therefore propose that no such factors be included.

9.4.4 Insurer credit risk event

The AER accepted our nomination of an insurer credit risk event and, as noted above, we accept that decision.

However, in accepting an insurer credit risk event as a pass through event the AER included, within the definition of that event, factors that it will take into account when it assesses a pass through application. We addressed generally, in Section 9.4.1 above, why the inclusion of such factors is inappropriate in the definition of any pass through event. We therefore propose that no such factors be included.

In addition to those general reasons, we also have quite specific concerns with the factors included by the AER. These concerns stem from observations made by the AER in its Preliminary Determination about the steps it considers that a NSP could take when an insurer becomes insolvent. In particular, we refer to the following statements by the AER[291]:

> *'As a result of … consultation [with SA Power Networks and others], we have clarified that we may allow NSPs to pass through claims that would have been made immediately after the insurer became insolvent and before the NSP had a reasonable opportunity to acquire new insurance for those risks. This amendment maintains an incentive on NSPs to acquire new insurance as soon as reasonably possible after an insurance provider becomes insolvent.'*

As part of the consultation with the AER on this matter, SA Power Networks highlighted that some of our insurance is occurrence based (ie based on when the insurance event occurred and not on when the claim is lodged). This means that SA Power Networks may not know if a past insurer has become insolvent and would therefore not be aware that it needs to try to find an insurer that is willing to retrospectively cover past events of which we have no knowledge because no claims have been lodged. Consequently, it may simply not be possible to take action to retrospectively reinsure past unknown events in all circumstances.

We therefore propose that these assessment factors be removed from the definition of an insurer credit risk event.

9.4.5 General nominated pass through event

The AER rejected our proposed general nominated pass through event, but we do not agree with the AER's reasoning.

---

[291] AER, *Preliminary Decision: SA Power Networks determination 2015−16 to 2019−20*, April 2015, page 15-15.

We do not, however, propose the inclusion of a general nominated pass through event in this Revised Proposal for the 2015-20 RCP. Instead, we propose the inclusion of a more specific 'terrorism event' (to which we consider our general nominated pass through event would have extended). We note that the AER has included a terrorism event as an additional nominated pass through event in its recent distribution determinations and preliminary decisions for other DNSPs in NSW, ACT and Queensland.

SA Power Networks proposes the following definition of a terrorism event for the 2015-20 RCP. This definition aligns with the definition adopted by the AER for the NSW distributors in their recent final Distribution Determinations, but with the removal of the assessment factors that the AER included in those determinations:

> *'A terrorism event occurs if:*
>
> *An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to SA Power Networks in providing direct control services.'*

Acceptance of the 'terrorism event' as a nominated pass through event is consistent with:

- the nominated pass through event considerations, as that term is defined in the NER (as addressed below);
- the policy intent for nominated pass through events – being that a NSP should not be in a position where it is unable to mitigate or avoid the event without creating unacceptable risk;[292] and
- the revenue and pricing principles in the NEL – specifically, that a regulated NSP should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control services.[293]

Nominated pass through event considerations

With respect to the nominated pass through event considerations:

a) The proposed terrorism event is not already covered by a category of pass through event specified in clauses 6.6.1(a1) (1) to (4) of the NER.

b) The nature and type of event can be clearly identified at the time of the determination as indicated by recent AER decisions.

c) SA Power Networks is not able to reasonably prevent an event of this nature or type from occurring or to substantially mitigate the cost impact of such an event. In addition, we note that, should an event occur and a pass through be sought, the AER will consider the efficiency of SA Power Networks' decisions and actions in relation to the risk of the event. Further, SA Power Networks has implemented a number of prudent measures to reduce the likelihood of such an event occurring. These include:[294]

292 AEMC, *Cost pass through arrangements for Network Service Providers*, Rule Determination, 2 August 2012, p 8.
293 NEL s 7(A)(2)(a).
294 SA Power Networks, *Regulatory Proposal 2015-20*, Supporting Document 20.103, p 18 to 19.

- SA Power Networks has an Asset Management Plan (AMP 5.1.03 Substation Fences and Security) which aims to reduce the risk of unauthorised entry to 'low' by the end of 2025;
- for all high risk substations, installation of appropriate security fence solutions and surveillance measures by 2020;
- installation of high security fencing as standard at high and medium risk locations for new substations and substations undergoing major upgrades;
- ongoing six monthly site and fence security inspections to ensure fences are maintained in serviceable condition; and
- ongoing review of current security measures and monitoring of latest developments in security systems and methods to develop innovative and cost effective site and technology security measures.

d) There are significant barriers to any NSP's ability to insure, or self-insure, against a terrorism event. In SA Power Networks' case, these include the following:

- SA Power Networks has commercial insurance cover which might potentially be triggered by a particular act of terrorism. However, SA Power Networks does not have specific cover for terrorism or cyber terrorism, as the market for such insurance is still developing. Consequently, obtaining insurance cover for this type of risk on commercial grounds is difficult. Of course, any payment that might be received under our commercial insurance would be deducted from the pass through amount; and
- The potentially significant magnitude of the cost of a terrorism event means that it is a risk that cannot be credibly fully self-insured by SA Power Networks. The low probability of such an event also means that there is a lack of data on which to base a reliable calculation of an efficient self-insurance premium.

9.4.6 Kangaroo Island cable failure event

The AER did not accept our proposed Kangaroo Island (**KI**) cable failure event. It detailed its reasons for the rejection of this event as follows:[295]

> *'We do not accept the Kangaroo Island cable failure event as a pass through event because we consider that a prudent service provider could reasonably prevent an event of this type from occurring.*
>
> *As discussed in Attachment 6, our preliminary decision includes a forecast of $47.2 million ($2014–15) in our alternative estimate of required capex for the 2015–2020 period to install a second undersea cable to Kangaroo Island.*
>
> *Under our assessment approach to nominated pass through events we have regard to who is best placed to bear the risk of the event occurring. All network service providers face risks associated with feeder cables failing. In our view, SA Power Networks is in a better position than consumers to bear the risk of this type of event. As noted in section 15.3, if the NSP has a degree of control, the availability of a pass through event can remove or dilute the incentive to manage the risk. We consider that allowing this event as a nominated pass through event may remove incentives on SA Power Networks to take adequate precautions in maintaining this cable. It is therefore inappropriate to transfer the risk of such an event to SA Power Networks' customers.'*

We consider that the AER's preliminary decision and reasons are incorrect and therefore do not accept its preliminary decision. Our responses to each of the AER's reasons are set out below.

---

[295] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 15-17 to 15-18.

A prudent service provider could reasonably prevent an event of this type from occurring

The AER asserts that a prudent service provider could reasonably prevent the existing submarine cable from failing. And yet, by approving the capital expenditure for the installation of the second KI cable, the AER has effectively accepted that SA Power Networks could not reasonably prevent this event from occurring.

The AER has accepted in its assessment of the expenditure for the installation of the second cable that the asset condition cannot be easily observed by stating:

> *'As 95 per cent of the KI undersea cable is buried, the condition of the asset cannot easily be observed. So we consider it is reasonable for alternative supply arrangements to be put in place for KI as the existing cable nears its 30 year life expectancy.'*[296]

By including the capital expenditure to install a second cable to KI, the AER has accepted that it is prudent to install a second cable or supply option prior to the failure of the existing submarine cable. It is prudent to do this on the basis that it will take 12 months to repair a deep sea fault and during that period the forecast operating costs of the generators to maintain electricity supply to customers would exceed $30 million, which is about 5% of SA Power Networks' average annual revenue requirement.

SA Power Networks is unaware of any existing proven technology that can monitor the condition of a 15 km undersea cable and accurately predict a failure at least 12 months prior to that failure, as this is the period required to ensure that a repair is carried out prior to the cable's failure. If this technology was available - which it is not - the costs to operate the generators to maintain supply would be reduced but may still be likely to exceed the one percent threshold.

The AER examined various other options (such as the prior purchase and storage of a second cable) to mitigate the costs of maintaining supply to KI but determined that the minimum cost to customers was to install a second supply to KI, recognising that the preferred option will be the subject of a RIT-D which requires a public consultation process.

SA Power Networks is in a better position than consumers to bear the risk of this type of event.

The AER's stated assessment approach is to '*have regard to who is best placed to bear the risk of an event occurring.*'[297] However, this is not a 'nominated pass through event consideration' as set down by the NER, and is, in our view, contrary to the revenue and pricing principles in section 7A of the NEL which provide that '*A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services*'. Without access to a pass through event SA Power Networks would not be able to recover its efficient costs (in the event of the existing cable failing) until the second cable/supply option is installed and operational.

In assessing a pass through application, the AER is required to assess whether the NSP prudently and efficiently managed the risks and minimised the costs associated with the pass through event. Clause 6.6.1(j)(3) of the NER provides that:

---

296 AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 6-64.
297 AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, p 15-17.

> *'the efficiency of the Distribution Network Service Provider's decisions and actions in relation to the risk of the positive change event, including whether the Distribution Network Service Provider has failed to take any action that could reasonably be taken to reduce the magnitude of the eligible pass through amount in respect of that positive change event and whether the Distribution Network Service Provider has taken or omitted to take any action where such action or omission has increased the magnitude of the amount in respect of that positive change event'.*

Where the AER determines that a NSP has not acted prudently or efficiently it can reduce the costs to be passed through to customers arising from the event. The NER envisages that consideration by the AER as to whether a NSP has prudently and efficiently managed the risk of an event is a post-event assessment matter; it is not a matter that is relevant to a determination as to whether an event should be approved (or rejected) as a nominated pass through event.

Acceptance of our proposed KI cable failure event will leave SA Power Networks facing the risk of costs being incurred from a failure of any land based sections of the cable, as those costs are unlikely to exceed the one percent materiality threshold applying under the NER to applications to pass through the costs.

However, it is inappropriate for SA Power Networks to bear the risk of a failure of any undersea section of the cable. Given the cable's (predominantly) undersea location, such a failure is clearly beyond our control, and as it is expected that a failure in that section of the cable would take 12 months or more to repair. SA Power Networks should not be expected to meet the costs of such a failure, especially where those costs will exceed one percent of its annual revenue requirement.

In approving the capital expenditure for the installation of the second KI submarine cable in its Preliminary Determination, the AER appears to have accepted that:

- the costs associated with a failure of the existing KI cable would be very significant;
- the only effective strategy to manage the risk of the current cable failing is to install a second supply to KI which is subject to a RIT-D; and
- SA Power Networks is not otherwise able to prudently and efficiently mitigate the effects of cable failure.

As customers have benefitted, and will continue to benefit, from the installation of the second cable being delayed until at least 2018, it is appropriate that they should bear the risk – by virtue of the Kangaroo Island cable failure pass through event – of costs being incurred as a result of the existing cable failing prior to the installation of the second cable/supply option.

All network service providers face risks associated with feeder cables failing

SA Power Networks does not disagree with the AER that distributors may be best placed to manage the risks associated with the failure of underground feeder cables. However, by its comment '*All network service providers face risks associated with feeder cables failing*', the AER implies that all DNSPs face the risk of a long (ie 15km) submarine cable failing. That is incorrect, as most DNSPs are clearly not exposed to that risk.

If an underground feeder cable section fails, customers are without supply for a short period of time until switching can be performed to isolate the failed section and restore supply to the customers via other cable(s). In the worst case scenario, a mobile generator can be used to restore and maintain supply to customers whilst the cable is being repaired. Whilst underground cables are less prone to failure than overhead power lines, they still fail routinely for a variety of reasons, and consequently the costs associated with such failures are included in a DNSP's base year allowances. The costs of repairing an underground feeder cable are generally less than $100,000.

However, if a section of the undersea cable was to fail, customers could be without supply for a year, unless the KI generators were operated at an estimated cost of greater than $30 million. In addition, the estimated cost to repair the cable is $11.4 (June 2015, $ million), which results in a total cost in excess of $41 (June 2015, $million). It is not possible for SA Power Networks to efficiently manage the risk of a failure of the submerged section of the cable which represents 95% of its length. Consequently, if this occurred and there was no proposed Kangaroo Island cable failure event under which SA Power Networks could pass through that cost to consumers, SA Power Networks would not be provided with a reasonable opportunity to recover its efficient costs in providing direct control services, which is contrary to the revenue and pricing principles under the NEL.

SA Power Networks would face the risk of a failure in the land sections of the undersea cable, which would incur considerable cost but is unlikely to exceed the 1% of revenue materiality threshold of about $6 million.

SA Power Networks has already taken all reasonable steps that a prudent NSP would take to mitigate the time that would need to be taken to repair the submarine cable in the event of a failure. Those actions include having:

- developed emergency response plans in the event of a failure of the cable; and
- stocked suitable spares to enable the cable to be repaired (ie lengths of cable and joints).

SA Power Networks considers that it will take a minimum of 24 months for the second cable to be installed or possibly longer if a non-network alternative was selected as the preferred option via the RIT-D. In addition, we have prudently obtained governmental Development Approval to install the second cable, as having this approval in place ahead of time shortens the time that would otherwise be required to install the second cable.

Summary - Installation of the second cable

As highlighted above and in the business case submitted with our Original Proposal, SA Power Networks has taken all reasonable and prudent steps to expedite the installation of the second cable.

Despite this, it is still expected to take 24 months to install the cable with the installation planned for 2018, which is subject to a RIT-D. The timeline for installation depends on several external factors over which SA Power Networks does not have control, which are:

- finalisation of the RIT-D;
- manufacture of 15kms of cable (lead times are in excess of 12 months);
- availability of suitable cable laying ships/barges; and
- suitable ocean conditions to lay the cable.

Customers have benefited from the postponement of installation of the second cable to date, and so it is customers who should bear the risk of the additional costs if the cable fails in the period before the second cable is installed and operating. If the cable fails and SA Power Networks was to operate the KI generators to maintain supply to the Island, then SA Power Networks' ability to provide direct control services would be compromised, as the annual cost to operate the generators is estimated to be approximately 5% of our proposed annual revenue requirement.

Consequently, SA Power Networks proposes in this Revised Proposal the inclusion of a Kangaroo Island cable failure event as a nominated pass through event, as set out in Section 9.5 below.

9.4.7 Native title event

SA Power Networks notes the AER's rejection of our proposed native title event.

We disagree with the AER's reasoning for rejecting that proposed event. However, we do not propose a native title pass through event in this Revised Proposal for the 2015-20 RCP.

9.5 Revised Proposal

In this Revised Proposal, SA Power Networks:

- accepts the AER's decision that each of the following events is a nominated pass through event for the 2015-20 RCP:
  - natural disaster event;
  - insurance cap event; and
  - insurer credit risk event; but
- has amended:
  - the AER's proposed definition of natural disaster event to:
    - remove the word' major' as well as the sentence that defines the word 'major';
    - include a reference to 'significant weather'; and
    - remove the words 'provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider '; and
  - the AER's proposed definitions of all three of the above events to remove the references to assessment criteria;
- has not accepted the AER's decision to reject the Kangaroo Island cable failure event as a nominated pass through event, and proposes the inclusion of a Kangaroo Island cable failure event; and
- proposes a terrorism event in place of the wider general nominated pass through event that was included in our Original Proposal and rejected in the AER's Preliminary Determination.

The definitions of the pass through events we propose as part of this Revised Proposal are as follows:

9.5.1 Natural disaster event

A natural disaster event occurs if:

> Any fire, significant weather (as reported by the BoM), flood, earthquake or other natural disaster occurs during the 2015-20 regulatory control period and materially increases the costs to SA Power Networks in providing direct control services.

9.5.2 Insurance cap event

An insurance cap event occurs if:

1) SA Power Networks makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy;
2) SA Power Networks incurs costs beyond the relevant policy limit; and
3) the costs beyond the relevant policy limit materially increase the costs to SA Power Networks in providing direct control services.

For this insurance cap event:

4) the relevant policy limit is the greater of:
    a. SA Power Networks actual policy limit at the time of the event that gives, or would have given rise to a claim; and
    b. the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the regulatory control period in which the insurance policy is issued.
5) A relevant insurance policy is an insurance policy held during the 2015-20 RCP or a previous RCP in which SA Power Networks was regulated.

9.5.3 Insurer credit risk event

An insurer's credit risk event occurs if:

A nominated insurer of SA Power Networks becomes insolvent, and as a result, in respect of an existing or potential insurance claim for a risk that was insured by the insolvent insurer, SA Power Networks:

1) is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or
2) incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.

9.5.4 Kangaroo Island cable failure event

A Kangaroo Island cable failure event occurs if:

Any failure of the SA Power Networks 33kV undersea cable supplying Kangaroo Island which is beyond the control of SA Power Networks that occurs during the regulatory control period and materially increases the costs to SA Power Networks of providing direct control services.

9.5.5 Terrorism event

A terrorism event occurs if:

An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to SA Power Networks in providing direct control services.

10. Incentive schemes

10.1 Capital Expenditure Sharing Scheme (CESS)

From 1 July 2015, the AER will apply an ex-ante CESS to provide financial rewards for DNSPs whose capital expenditure becomes more efficient and impose financial penalties for those DNSPs that become less efficient, over a RCP.

10.1.1 Rule requirements

Clause 6.5.8A of the NER sets out the factors that the AER is required to take into account in developing a CESS. In deciding the nature and details of any CESS to apply, the AER must:

- make that decision in a manner that contributes to the achievement of the capital expenditure incentive objective;[298] and
- consider the CESS principles,[299] the interaction of the CESS with incentive schemes, capital expenditure objectives,[300] and where relevant the operating expenditure objectives, as they apply to the particular DNSP, and the circumstances of the DNSP.[301]

The AER will also introduce ex-post measures to ensure that only efficient capital expenditure enters the Regulated Asset Base (**RAB**). These ex-post measures are derived from clause S6.2.2A of the NER which outlines the circumstances in which the AER may reduce the amount by which a DNSP's RAB is to be increased as part of the RAB roll forward. However, these ex-post measures will not apply to SA Power Networks until the 2020-25 regulatory determination process.

10.1.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks supported the introduction of the CESS for the 2015-20 RCP[302]. In tandem with the Efficiency Benefit Sharing Scheme (**EBSS**), the CESS provides appropriate and balanced incentives for efficient expenditure.

The ex-post review will be undertaken for the first time as part of the distribution determination process for the 2020-25 RCP. Typically, the relevant period over which the assessment is to occur (ie the review period) is the first three years of the RCP just ending and the last two years of the preceding RCP. This differs from the period for the CESS. In our Original Proposal, SA Power Networks also advocated for full and transparent consultation at any stage of any ex-post review.[303]

10.1.3 AER's Preliminary Determination

In its Preliminary Determination, the AER states that it will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to SA Power Networks in the 2015-20 RCP.[304] This is consistent with the proposed approach set out in the AER's Framework and Approach Paper (**F&A**).[305]

---

[298] Clause 6.5.8A(e) of the NER.
[299] Clause 6.5.8A(c) of the NER.
[300] Clause 6.5.8A(d) of the NER.
[301] Clause 6.5.8A(e) of the NER.
[302] SA Power Networks, *Regulatory Proposal 2015-20*, October 2014, page 279.
[303] Ibid.
[304] AER, *Preliminary Decision: SA Power Networks' determination 2015-16 to 2019-20*, April 2015, page10-6.
[305] AER, *Preliminary positions paper, Framework and approach for SA Power Networks, Regulatory control period commencing 1 July 2015,* December 2013, page 59.

10.1.4 SA Power Networks' response to AER Preliminary Determination

SA Power Network supports the AER's decision to apply the CESS for the 2015-20 RCP.

However, SA Power Networks proposes that costs associated with implementing certain changes to the NER be excluded from the CESS and the EBSS in the 2015-20 RCP. This includes the forthcoming changes that will complete the current phase of the Power of Choice reform program.

We consider that it is possible that many (if not all) of these staggered costs may not, individually, exceed the materiality threshold of the 'regulatory change' pass through event prescribed by clause 6.6.1(a1)(1) of the NER. As such, it is both unreasonable and inconsistent with the revenue and pricing principles in the NEL that DNSPs should be provided with a reasonable opportunity to recover at least their efficient costs,[306] for SA Power Networks to be penalised for incurring costs to implement Rule changes, a number of which are imminent.

Our Revised Proposal includes forecast expenditure to implement new tariff structures associated with the AEMC's Distribution Network Pricing Arrangements Rule change which was finalised and commenced in November 2014. However, the potentially wide-ranging impacts from a number of other new or draft Rule changes are not yet known and are subject to various factors. We have not been able to include costs for these matters in our Revised Proposal. Some of the anticipated changes include:

- Expanding Competition in Metering and Related Services Rule change – This Rule change will be finalised in July 2015. However, ring fencing requirements are yet to be defined by the AER, and shared market protocol changes are yet to be developed by AEMO but are expected to fundamentally change how meter data is delivered and received by SA Power Networks, necessitating significant IT changes;
- Customer Access to Information about their Electricity Consumption Rule change – This Rule change was finalised and commenced in November 2014. However, AEMO is currently consulting on minimum specifications and file formats, and other systems changes are dependent on the volume of requests from customers; and
- Improving Demand Side Participation Information provided to AEMO by Registered Participants Rule change – This Rule change was finalised and commenced in March 2015. However, AEMO is yet to develop the relevant Guidelines that SA Power Networks will need to comply with in the 2015-20 RCP.

In addition to these more imminent changes, other Power of Choice reform program Rule changes are being considered which could result in further costs being incurred by SA Power Networks in the 2015-20 RCP. These Rule changes include:

- Demand management and embedded generation connection incentive scheme;
- Demand response mechanisms – option for demand side resources to participate in the wholesale electricity market;
- Embedded networks; and
- Multiple trading relationships.

It is also likely that the costs associated with these individual Rule changes will not exceed the materiality thresholds applicable to pass through events and, therefore, we would be unable to seek a pass through for these costs.

---

[306] Section 7A(2) of the NEL.

10.1.5 Revised Proposal

In the 2015-20 RCP, SA Power Networks could potentially incur significant capital and operating costs to implement systems and other changes to meet new regulatory requirements imposed by Power of Choice and other Rule changes.

If and when SA Power Networks incurs costs in the 2015-20 RCP arising from regulatory changes that have not been taken into account in the AER's Final Determination or will be unable to be recovered through the pass through event mechanism because of the high materiality threshold, these costs should be excluded from the CESS and the EBSS.

10.2 Efficiency Benefit Share Scheme (EBSS)

The EBSS provides an incentive for DNSPs to pursue efficiency improvements in operating expenditure. The AER will apply version two of the EBSS to SA Power Networks, to provide SA Power Networks with a continuous incentive to pursue efficiency gains during the 2015-20 RCP.

This section deals with two separate aspects of the EBSS:

- the calculation of the EBSS carryover amounts from the 2010-15 RCP, which are used in the calculation of SA Power Networks' annual revenue requirement for the 2015-20 RCP; and
- the way in which the EBSS is to be applied in the 2015-20 RCP.

10.2.1 Rule requirements

The EBSS which applies to SA Power Networks in the 2010-15 RCP (and which gives rise to revenue increments and decrements for the 2015-20 RCP) is the EBSS specified in the 2010 Determination.[307] This determination refers to the EBSS as set out in the AER's 2008 F&A for ETSA Utilities,[308] which in turn refers to the distribution EBSS established by the AER in June 2008.[309]

The 2010 Determination identifies certain categories of operating expenditure which are to be excluded from the operation of the EBSS for the 2010-15 RCP, and provides for the deferral of certain carryover amounts accrued in the 2005-10 RCP under the previous Essential Services Commission of South Australia (ESCoSA) scheme.

The EBSS to apply in the 2015-20 RCP must be developed and implemented in accordance with clause 6.5.8 of the Rules. This specifies that the AER must have regard to the following matters in developing and implementing an EBSS for the 2015-20 RCP.[310]

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs;
- the need to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure;
- the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses;
- any incentives that DNSPs may have to capitalise expenditure; and

---

[307] AER, *ETSA Utilities distribution determination 2010–11 to 2014–2015*, 4 May 2010.
[308] AER, *Framework and approach paper: ETSA Utilities 2010–2015,* November 2008.
[309] AER, *Electricity distribution network service providers: Efficiency benefit sharing scheme*, June 2008.
[310] Clause 6.5.8(c) of the NER.

- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

10.2.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks calculated carryover amounts for the 2010-15 RCP, in accordance with the EBSS which applied during that period (as set out in the 2010 Determination) and the relevant requirements of the NER.

SA Power Networks proposed a total carryover amount for the 2010-15 RCP of $13.9 (June 2015, $ million) as set out in Table 10.1.[311]

Table 10.1: SA Power Networks' proposed EBSS carryover amounts for the 2015-20 period (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20
Total carryover	10.1	16.3	0.1	(12.6)	-

SA Power Networks' calculation of the proposed carryover amount was based on its actual operating expenditure for the 2010-15 RCP, adjusted for:

- costs associated with approved pass through events during the 2010-15 RCP;
- costs in the uncontrollable cost categories identified by the AER in the 2010 Determination; and
- costs in two other specific uncontrollable cost categories, being guaranteed service level (GSL) payments associated with major event days (**MEDs**) and regulatory compliance costs associated with new reporting requirements under the AER's Better Regulation program.

In our Original Proposal, SA Power Networks supported the continued application of the EBSS in the 2015-20 RCP. SA Power Networks also generally supported the AER's proposed approach to application of this scheme for the 2015-20 RCP, as set out in the EBSS published by the AER in November 2013, and the F&A, subject to the retention of specific exclusions and adjustments. These specific exclusions and adjustments include those that applied in the 2010-15 RCP, for the purposes of applying the EBSS in the 2015-20 RCP,[312] namely:

- debt raising costs;
- insurance and self-insurance costs;
- superannuation costs for defined benefits and retirement schemes; and
- the demand management innovation allowance (**DMIA**).

Additionally, SA Power Networks proposed to exclude MED-related duration GSL payments from the operation of the EBSS in the 2015-20 RCP.[313]

10.2.3 AER's Preliminary Determination

In its Preliminary Determination, the AER amended SA Power Networks' EBSS carryover for the 2010-15 RCP to (-$4.7 (June 2015, $ million)), as set out in Table 10.2.[314]

[311] SA Power Networks, *Regulatory Proposal 2015-2020*, October 2014, page 280.
[312] Ibid, page 290.
[313] AER, Preliminary Decision: SA Power Networks' determination 2015-16 to 2019-20, April 2015, page 9-6.

Table 10.2: AER's preliminary decision on SA Power Networks' EBSS carryover amounts (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20
Total carryover	(0.7)	(5.0)	(2.7)	3.8	-

The EBSS carryover in the AER's Preliminary Determination of -$4.7 (June 2015, $ million) is different to the carryover proposed by SA Power Networks of $13.9 (June 2015, $ million) as the AER.[315]

- excluded from the EBSS movements in provisions that SA Power Networks treated as opex resulting in an adjustments of -$26.3 (June 2015, $ million) to SA Power Networks' proposed carryover amount;
- did not exclude from the EBSS costs for either MED-related GSL payments or regulatory compliance costs resulting in an adjustments of -$28.7 (June 2015, $ million) to SA Power Networks' proposed carryover amount; and
- did not apply the deferred negative carryover from the 2005–10 RCP accrued under the Efficiency Carryover Mechanism resulting in an adjustments of $36.4 (June 2015, $ million) to SA Power Networks' proposed carryover amount.

The AER has determined that it will apply version two of the EBSS to provide SA Power Networks with a continuous incentive to pursue efficiency gains during the 2015-20 RCP.[316] The AER has adjusted actual operating expenditure under the EBSS for the 2015-20 RCP to reverse any movements in provisions. The AER's preliminary decision is also to exclude the following categories of costs from the EBSS[317]:

- debt raising costs; and
- DMIA.

The AER does not propose to exclude operating expenditure on self-insurance, insurance or superannuation for defined benefits and retirement schemes on the basis that they will be included in the revealed year base costs. Non-network alternative expenditure will also not be excluded due to the balance of incentives between operating expenditure and capital expenditure with the introduction of the CESS.

The AER has not excluded MED-related duration GSL payments as proposed by SA Power Networks as the AER no longer considers uncontrollability to be a reason for a cost category to be excluded from the EBSS[318].

In addition to the excluded cost categories the AER will also:[319]

- adjust forecast operating expenditure to add (subtract) any approved revenue increments (decrements) made after the Preliminary Determination. This may include approved pass through amounts;

---

[314] Ibid.
[315] Ibid page 9-10.
[316] Ibid, page 9-13.
[317] Ibid, page 9-14.
[318] Ibid.
[319] Ibid, page 9-15.

- adjust actual operating expenditure to add capitalised operating expenditure that has been excluded from the RAB; and
- exclude categories of operating expenditure not forecast using a single year revealed cost approach for the RCP beginning in 2020 where the AER deems that doing so will better achieve the requirements of clause 6.5.8 of the NER.

10.2.4 SA Power Networks' response to AER Preliminary Determination

Carryover amounts accrued during the 2010-15 RCP

In its Preliminary Determination, the AER does not accept SA Power Networks' proposed EBSS carryover amounts.[320] The AER made the following adjustments to the calculation of carryover amounts:

- movements in provisions were excluded by the AER from the EBSS calculations;
- uncontrollable costs associated with MED-related GSL payments and regulatory compliance were included; and
- the deferred carryover from the 2005-10 RCP was not included, on the basis that overall carryover from the 2010-15 RCP (as calculated by the AER) is not positive.

The last of these changes is consistent with SA Power Networks' Original Proposal. As noted in our Original Proposal, the deferred carryover from the 2005-10 RCP can only be used to offset a positive carryover from the 2010-15 RCP, should a positive carryover arise. Since the other changes made by the AER lead to an overall negative carryover for the 2010-15 RCP, the carryover from the previous period cannot be included in the calculation. The AER concludes that '*While there may be an option to defer the negative carryover accrued during the 2005-10 regulatory control period under the ECM for a further five years, we see no reason to do so*'.[321] We agree with this position.

For reasons set out in our Original Proposal, SA Power Networks maintains its position that uncontrollable costs associated with MED-related GSL payments and regulatory compliance should be excluded from the EBSS calculation. We also consider that movements in provisions should be included in the calculation.

Nevertheless, subject to the following paragraph, SA Power Networks accepts the overall decision of the AER on EBSS carryover amounts from the 2010-15 RCP. We have therefore included the carryover amounts calculated by the AER in our calculation of the annual revenue requirements for the 2015-20 RCP.

However should the AER change its position on the calculation of EBSS carryover amounts prior to making its Final Determination, SA Power Networks would expect to be notified of this, and to be given an opportunity to comment on any proposed changes to the calculation. If the AER was to change its position on any aspect of the calculation, this may alter our view as to the reasonableness of the AER's overall decision on this issue.

Application of the EBSS in the 2015-20 RCP

SA Power Networks accepts the AER's preliminary decision on how the EBSS is to apply in the 2015-20 RCP.

---

[320] AER, *Preliminary Decision: SA Power Networks' determination 2015-16 to 2019-20*, April 2015, page 9-6.
[321] Ibid, page 9-13.

We note that the AER does not propose to make all of the exclusions from the calculation of EBSS amounts that were proposed by SA Power Networks, such as for self-insurance, insurance and uncontrollable cost categories. This means that the risk of forecasting error associated with uncontrollable events is effectively borne by SA Power Networks, since the EBSS will reward or penalise us for such errors. However, since the risk of forecasting error associated with uncontrollable events is likely to be approximately symmetrical, we are prepared to accept the AER's decision on the exclusion of most of these cost categories in the EBSS.

As detailed in Section 10.1.4, we propose, however, that costs associated with implementing certain Rule changes, such as the forthcoming Rule changes that will complete the current phase of the Power of Choice reform program, be excluded from the EBSS and the CESS in the 2015-20 RCP. Our reasoning, as stated in Section 10.1.4 equally applies to the EBSS, and so is not repeated here.

10.2.5 Revised Proposal

In the 2015-20 RCP SA Power Networks could potentially incur significant capital and operating costs to implement systems and other changes to meet new regulatory requirements imposed by Power of Choice and other Rule changes.

If and when SA Power Networks incurs costs in the 2015-20 RCP arising from regulatory changes that have not been taken into account in the AER's Final Determination or will be unable to be recovered through the pass through event mechanism because of the high materiality threshold, these costs should be excluded from both the EBSS and the CESS.

10.3 Service Target Performance Incentive Scheme (STPIS)

The AER's F&A advised that the standard national STPIS would apply to SA Power Networks for the 2015-20 RCP. The national regime utilises the natural logarithm method to normalise daily System Average Interruption Duration Index (**SAIDI**) data to determine the Major Event Day (**MED**) SAIDI threshold. In addition, the national STPIS method employees a ±5% revenue at risk cap (ie setting the maximum bonus or penalty) for each year of a RCP.

The adoption of the national STPIS requires SA Power Networks to propose a method to transition STPIS parameters' targets from the existing to the new arrangements, as was submitted in our Original Proposal.

10.3.1 Rule requirements

The AER's national STPIS scheme comprises the following two mechanisms:

- a service standards factor (**s-factor**) adjustment to annual revenue allowances rewarding/penalising distributors for better/worse performance compared with predetermined targets pertaining to supply quality, supply reliability and customer service; and
- a guaranteed service level (**GSL**) component whereby customers are paid directly if they experience service below a predetermined level.

The STPIS GSL component does not apply to SA Power Networks as a consequence of the Essential Services Commission of South Australia (**ESCoSA**) implementing a jurisdictional GSL regime. In the lead up to SA Power Networks' 2015-20 RCP ESCoSA established a revised service standard framework which maintained inclusion of a GSL scheme. The framework also incorporates reliability and customer service (ie telephone response) performance measures and service standard targets.

Version 1.2 of the AER's STPIS published in November 2009 sets out the national incentive regime that applies to ensure that the performance delivered by DNSPs to customers will not decline, but will instead be improved or maintained, over a RCP. The STPIS defines the performance measures and the exclusions that will apply to those measures (eg exclusion of performance on MEDs). The STPIS incorporates possible amendments to the regime that can be submitted by a DNSP which can be used once approved by the AER. The AER defines the STPIS measures and the targets that will apply to a DNSP in its distribution determination.

10.3.2 SA Power Networks' Original Proposal

As part of its 2010 Distribution Determination for SA Power Networks, the AER approved that MEDs (ie the days excluded from the STPIS performance measures' results) would be determined using the Box-Cox (**BC**) method for calculating the MED daily SAIDI threshold (ie any day where the daily SAIDI exceeded the threshold was classified as a MED). This was a variation to the standard STPIS methodology, which determined the SAIDI threshold by using the natural logarithm (**LN**) method.

The STPIS financial outcome for any year is based on the difference between the actual parameters' performance for that year and each parameter's fixed annual targets as established in the distribution determination for that RCP. The STPIS parameters' fixed annual targets for each RCP are based on the actual STPIS performance for each of the preceding five years, provided there is no capping of the STPIS outcome for any of those years.

The AER specified in its F&A that the standard STPIS would apply to SA Power Networks during the 2015-20 RCP. This required a re-calculation of the STPIS annual parameters' actual performance that was previously determined using the BC method. In addition, it invoked the requirement for a suitable method to transition the STPIS parameter targets from the 2010-15 RCP to the 2015-20 RCP.

A suitable transition method was required as the LN method resulted in fewer MEDs than the BC method. As a consequence of the fewer MEDs, seven of the nine years' STPIS parameters' actual performances required amendment, including those used to establish the STPIS parameter targets for each regulatory year of the 2010-15 RCP.

SA Power Networks proposed a suitable transition method in our Original Proposal. The method effectively determined the annual STPIS parameter performance for each year of the 2010-15 RCP by reproducing an equivalent average difference between that regulatory year's performance and the re-calculated parameter targets. This method matched the STPIS outcomes (ie the percentage of the revenue decrement or increment) for each regulatory year of the 2010-15 RCP as if the LN method had applied to the 2010-15 RCP. This method ensured that SA Power Networks and its customers were kept financially neutral.

This method was used to adjust the reliability and telephone response raw annual parameters' performance as determined using the LN method.

10.3.3 AER's Preliminary Determination

In its Preliminary Determination, the AER accepted SA Power Networks' proposed method to transition both the reliability and telephone response measures from the 2010-15 to the 2015-20 RCP arrangements. The AER also accepted our proposed targets, albeit with some minor modification to the STPIS SAIDI reliability targets which reflected their use of two decimal places compared to our proposed targets that adopted one decimal place. This resulted in the CBD and Rural Short SAIDI targets being adjusted slightly.

The AER also incorporated into its STPIS reliability incentive rates AEMO's recent findings on the Value of Customer Reliability (**VCR**). The inclusion of AEMO's VCR materially reduces the incentives for improvement in reliability performance. AEMO's findings do not impact the incentive for improvements in telephone response.

The AER's preliminary decision of STPIS targets to apply to SA Power Networks in the 2015-20 RCP[322] is shown in Table 10.3.

Table 10.3: AER preliminary decision on STPIS reliability targets for the 2015-20 RCP

		2015/16	2016/17	2017/18	2018/19	2019/20
SAIDI (minutes)	CBD	12.48	12.48	12.48	12.48	12.48
	Urban	121.50	121.50	121.50	121.50	121.50
	Short rural	231.06	231.06	231.06	231.06	231.06
	Long rural	311.70	311.70	311.70	311.70	311.70
SAIFI (number)	CBD	0.132	0.132	0.132	0.132	0.132
	Urban	1.353	1.353	1.353	1.353	1.353
	Short rural	1.930	1.930	1.930	1.930	1.930
	Long rural	2.027	2.027	2.027	2.027	2.027

[322] AER, *Preliminary Decision: SA Power Networks' determination 2015-16 to 2019-20*, April 2015, Table 11.4, page 11-14.

The AER's preliminary decision of incentive rates to apply to SA Power Networks' STPIS targets in the 2015-20 RCP[323] is shown in Table 10.4.

Table 10.4: AER preliminary decision on STPIS incentive rates for the 2015-20 RCP

	CBD	Urban	Rural short	Rural long
SAIDI (minutes)	0.0035	0.0404	0.0077	0.0075
SAIFI (number)	0.2961	3.7379	1.0068	1.2600

10.3.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks accepts the AER's preliminary decision on the STPIS regime, including the reduction in incentive due to the lower VCR rates.

SA Power Networks notes that the AER has adjusted the VCR rates so that they align with AEMO's recent findings, and has applied AEMO's VCR rates to all of its recent distribution determinations. SA Power Networks supports the adoption of the lower VCR values as it reflects the latest findings on the value that customers place on reliability, however, the adoption of the lower incentive rates reduces the options for DNSPs to improve reliability performance for customers.

It is our view that the AER has an opportunity to both reflect updated VCR findings as well as maintain appropriate incentives to SA Power Networks to improve reliability under the STPIS arrangements. In this regard, SA Power Networks observes that the AER has not amended the STPIS prior to making its Preliminary Determination. Had it done so the STPIS arrangements could have been amended to incorporate important developments in other areas.

Before its Final Determination is required to be made, the AER should consider the AEMC's final report to the COAG Energy Council on the measures and definitions that are included in the National Reliability Reporting Framework, and specifically those recommendations relating to the definition of Momentary Average Interruption Frequency Index (**MAIFI**).

In relation to MAIFI, the AEMC made the following statement in its final report.[324]

> *'The recommended change to the definition of a momentary interruption and a momentary interruption event from less than one minute to less than three minutes would increase the flexibility and options for distribution automation systems, which potentially reduces their cost. The AER and the distributors generally support our proposal, although SP-AusNet notes there may be transitional issues for distributors with distribution automation systems that have been purposely built to meet the one minute standard. Similarly various consumer advocacy bodies supported this change.'*

The AEMC's National Reliability Reporting Framework is strongly aligned with the AER's STPIS except that the framework utilises Momentary Average Interruption Frequency Index events (ie **MAIFIe**) instead of the MAIFI specified in the AER's STPIS. As a consequence of the adoption of MAIFIe in the

[323] AER, *Preliminary Decision: SA Power Networks' determination 2015-16 to 2019-20*, April 2015, Table 11.5, page 11-16.
[324] AEMC, *Review of Distribution Reliability Measures*, Final Report, 5 September 2014, Sydney Executive Summary page I and ii.

Framework, the AEMC's definition of momentary interruptions is '*an Interruption to a Distribution Customer's electricity supply with duration of 3 minutes or less*'.[325]

The main reason provided by the AEMC to increase momentary interruptions' duration from one to three minutes was that it '*would increase the flexibility and the options for distribution automation systems, which potentially reduces their cost.*'[326] In addition, the extension of the momentary interruption duration from one minute to three minutes aligns the AEMC's Framework with European standards (including those adopted by the United Kingdom's OFGEM).

Given the far lower VCR applying in the 2015-20 RCP, in the absence of a change in the MAIFI definition, implementation of automation systems may be too high risk and/or too costly to attempt to enable sub-one minute restoration times. As a consequence, if changes to the MAIFI definition are delayed until the AER undertakes a full STPIS review; our customers may miss out on improvements in reliability due to the reduced incentives arising from both the lower VCR rate and retention of the AER's less flexible momentary interruption definition.

Customer Feedback

SA Power Networks' customer engagement program (**CEP**) included a comprehensive on-line survey. In the survey, a specific question was asked in relation to amending the definition of a momentary interruption from less than one minute to three minutes. The answer to that specific question indicates that an increase in allowable momentary interruption duration, from one to three minutes, is not of concern to our customers. The specific question and background provided in the online survey are as follows:

> *'Question 3: Manual restoration of supply interruptions is performed by emergency response crews. In very limited network locations, new network automation systems (eg: remotely controlled network switches) allow 'automatic' restoration in a matter of minutes.*
>
> *Regulated service standards define short term interruptions as less than one minute duration, but network automation systems cannot respond this quickly. To promote more widespread automatic restoration of power to more customers, regulated service standards would need to be amended to define a short term interruption as being a maximum of three minutes, for example, instead of one minute currently.*
>
> *Q: What would be the impact of a three minute interruption, as opposed to a one minute interruption, to your household/business?'*

The majority of respondents (98%) across all of our customer segments indicated that a three minute interruption would have minimal to no impact on their household or business when compared to a one minute interruption.

[325] AEMC, *Review of Distribution Reliability Measures: Final Report*, 5 September 2014, page 11.
[326] Ibid, page ii.

SAIDI and SAIFI modelling

SA Power Networks has modelled the resultant average contribution to normalised (ie excluding LN MEDs) SAIDI and SAIFI over the period from 2009/10 to 2013/14 arising from the proposed definitional change to MAIFI from one minute to three minutes. The average contributions are detailed in Table 10.5 which demonstrates that the impact upon SAIDI and SAIFI are negligible.

Table 10.5: Reliability average contribution from interruptions of 3 minutes or less and more than 1 minute over the period from 2009/10 to 2013/14

	CBD	Urban	Rural Short	Rural Long	Dist System
SAIDI (minutes)	0.00762	0.1133	0.0656	0.1091	0.103
SAIFI (number)	0.00266	0.04	0.03402	0.04836	0.0446

If the AER was to adopt the AEMC's National Reliability Reporting Framework's momentary interruption definition then the STPIS reliability targets should be set at the levels outlined in Table 10.6.

Table 10.6: STPIS reliability targets excluding interruptions of 3 minutes or less in duration

	CBD	Urban	Rural Short	Rural Long
SAIDI (minutes)	12.49	121.48	231.03	311.64
SAIFI (number)	0.132	1.323	1.906	2.003

10.3.5 Revised Proposal

SA Power Networks accepts the AER's preliminary decision on the STPIS regime, including the reduction of the incentive due to the lower VCR rates.

However, SA Power Networks proposes that the AER adopts the three minute momentary interruption definition for the STPIS regime that will apply to SA Power Networks for the 2015-20 RCP. Accordingly, the STPIS reliability targets should be adjusted to those detailed in Table 10.6.

10.4 Demand Management Incentive Scheme (DMIS)

A DMIS has applied to SA Power Networks in the 2010-15 RCP. The current scheme includes a Demand Management Incentive Allowance (**DMIA**), a capped allowance to investigate and conduct broad-based and/or peak demand management projects.

10.4.1 Rule requirements

The NER require the AER to develop and implement mechanisms to incentivise DNSPs to consider economically efficient alternatives to building more network.

Clause 6.6.3 of the NER sets out the factors to which the AER must have regard to in implementing a DMIS

10.4.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks supported the AER's position to continue with the DMIA at the proposed amount of $600,000 each year in the 2015-20 RCP.[327]

10.4.3 AER's Preliminary Determination

In its Preliminary Determination, the AER has determined to continue to apply Part A of the DMIA to SA Power Networks in the 2015-20 RCP.[328] The AER will not apply Part B of the DMIA, relating to revenue foregone, to SA Power Networks in the 2015-20 RCP as it has applied a revenue cap form of control in the 2015-20 RCP.

10.4.4 SA Power Networks' response to the AER's Preliminary Determination

SA Power Networks supports the AER's preliminary decision to apply the DMIS for the 2015-20 RCP.

10.4.5 Revised Proposal

SA Power Networks has included provision for the DMIA of $3.0 (June 2015, $ million) in its Revised Proposal for the 2015-20 RCP.

[327] SA Power Networks, *Regulatory Proposal 2015-20*, October 2014, page 293.
[328] AER, *Preliminary Decision: SA Power Networks' determination 2015-16 to 2019–20*, page 12-6.

Page left blank intentionally

11. Shared Assets

In our Original Proposal, SA Power Networks proposed shared asset cost reductions of $2.5 (nominal, $ million). The AER accepted SA Power Networks' methodology for calculating shared asset unregulated revenues (**SAUR**), but has increased the shared asset cost reduction to $4.1 (nominal, $ million) on the basis that its SAUR meets the materiality threshold of 1% of annual revenue requirement (**ARR**) in all five years of the 2015-20 RCP.

11.1 Rule requirements

Where an asset is used to provide both SCS and unregulated services, clause 6.4.4 of the NER allows the AER to reduce SA Power Networks' SCS regulated revenue by an amount that the AER considers is reasonable to reflect such part of the cost of the asset that is being recovered through charging for unregulated services. Clause 6.4.4 of the NER requires the AER to have regard to the shared asset principles and the Shared Asset Guideline (**Guideline**) in determining shared asset cost reductions.

11.2 SA Power Networks' Original Proposal

Paragraph 2.4a. of the Guideline states that service providers may include in a regulatory proposal for a regulatory control period proposed cost reductions for the AER's approval.

SA Power Networks proposed a methodology for the estimation of SAUR, by calculating the sum of:

- for unregulated services that rely on the use of shared assets, such as pole rental and other facilities access or asset rental services — the unregulated revenue earned from those services; and
- for each unregulated service that uses shared assets insignificantly, such as unregulated project management, maintenance, or external training services that use vehicles, information technology and/or buildings, — the portion of that revenue that reflects the extent to which the service recovers the asset costs of relevant shared assets.

Where shared asset revenues are absorbed in overall project revenues, SA Power Networks has used the allocation apportioned by its approved Cost Allocation Method (**CAM**) to derive those revenues.

Shared asset cost reductions are subject to a materiality threshold. Unregulated use of shared assets is material when the SAUR in a specific regulatory year is expected to be greater than 1% of its total ARR for that regulatory year. Based on the ARR in SA Power Networks' Original Proposal, the SAUR met the materiality threshold for the first three years of the 2015-20 RCP only. SA Power Networks proposed a net shared asset cost reduction for the 2015-20 RCP of $2.5 (nominal, $ million) as set out in Table 11.1.

Table 11.1: SA Power Networks' proposed shared asset cost reduction 2015-20 (nominal, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20
Net shared asset cost reduction	0.821	0.821	0.821	-	-

11.3 AER's Preliminary Determination

In its Preliminary Determination, the AER has accepted SA Power Networks' methodology to forecast its SAUR. However the AER has reduced SA Power Networks' ARR in all years of the 2015-20 RCP in its Preliminary Determination, and on that basis has determined that SAUR is between 1.2 and 1.3% of total expected revenue in each regulatory year of the 2015-20 RCP. SAUR therefore meets the materiality threshold in each regulatory year.

Table 11.2: AER's preliminary decision on SA Power Networks' shared asset revenue adjustments (nominal, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20
Net shared asset cost reduction	0.821	0.821	0.821	0.821	0.821

11.4 SA Power Networks' response to AER Preliminary Determination

In this Revised Proposal, SA Power Networks has revised the forecast of our ARR. Based on the revised forecast; the materiality threshold of 1% of ARR is reached in only the first two years of the 2015-20 RCP. SA Power Networks has therefore revised its net shared asset cost reduction, but has continued to apply the methodology accepted by the AER in its Preliminary Determination.

11.5 Revised Proposal

SA Power Networks' SAUR is unchanged from the amount accepted by the AER in its Preliminary Determination. However, the ARR in this Revised Proposal has resulted in the materiality threshold being met in the first two years of the RCP only, as shown in Table 11.3.

Table 11.3: Materiality assessment

	2015/16	2016/17	2017/18	2018/19	2019/20
Average SAUR (nominal $million)	9.6	9.6	9.6	9.6	9.6
Smoothed ARR (nominal $million)	682.0	856.1	978.5	998.6	1,019.2
Average SAUR as a proportion of ARR (%)	1.39%	1.11%	0.97%	0.95%	0.93%
Material (Y/N)	Y	Y	N	N	N

SA Power Networks proposes a net shared asset cost reduction of $1.6 (nominal, $ million) for the 2015-20 RCP as set out in Table 11.4. The shared asset cost reduction has reduced marginally in each of the first two years of the 2015-20 RCP from that accepted in the AER's Preliminary Determination due to a revision in the forecast CPI that has been applied, as described in Chapter 13 (Weighted Average Cost of Capital).

Table 11.4: Revised Proposal shared asset cost reduction 2015-20 (nominal, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20
Net shared asset cost reduction	0.814	0.814	-	-	-

A revised Shared Assets Revenue Model to reflect the above changes is contained in Attachment K.1.

Page left blank intentionally

12. Regulated asset base

12.1 Rule requirements

Clause 6.5.1 of the NER describes the nature of the regulatory asset base (**RAB**) for SCS. It requires the AER to develop and publish a model for the roll forward of the RAB and provides the requirements for the roll forward model (**RFM**).

Clause S6.1.3(7) of the NER requires a building block proposal to contain a calculation of the RAB for each regulatory year of the relevant RCP, using the RFM, together with:

- details of all amounts, values and other inputs;
- a demonstration that the amounts, values and inputs comply with the relevant requirements of Part C of Chapter 6 of the NER; and
- an explanation of the calculation of the RAB for each regulatory year and of the amounts, values and other inputs involved in the calculation.

Clause S6.1.3(10) of the NER requires a building block proposal to contain a Post Tax Revenue Model (**PTRM**) completed to show its application to the RFM.
Other provisions relating to the RAB are set out in clause S6.2 of the Rules. In particular:

- subclause S6.2.1(e) specifies the method of adjustment of the value of the RAB between RCPs; and
- sub-clause S6.2.3 specifies the method of adjustment of the value of the RAB for each regulatory year within a RCP.

12.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks rolled forward the RAB to 30 June 2020 using the AER's RFM and PTRM in accordance with the NER.

In doing this, SA Power Networks:

- determined the roll forward of the RAB value from 1 July 2010 to 30 June 2015 to be $3,829.4 (nominal, $ million) for SCS;
- determined the roll forward of the RAB value from 1 July 2015 to 30 June 2020 to be $5,623.1 (nominal, $ million) for SCS; and
- proposed to apply a forecast depreciation approach to establish the RAB at 30 June 2020, consistent with the Framework and Approach paper (**F&A**).

12.3 AER's Preliminary Determination

In its Preliminary Determination, the AER accepted our proposed opening RAB and tax asset base at 1 July 2015 as well as our proposed application of forecast depreciation to roll forward the RAB to 30 June 2020. As part of the Final Determination, the AER expects to update the 2014/15 regulatory year estimated capital expenditure with more up to date estimates or actuals.

However, the AER determined a forecast closing RAB value at 30 June 2020 of $5,132.5 (nominal, $ million). This lower value reflects the AER's preliminary decisions on forecast capital expenditure and forecast regulatory depreciation.

12.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks accepts the AER's preliminary decisions:

- to accept the proposed opening RAB and tax asset base at 30 June 2015; and
- to apply forecast depreciation to establish the RAB at 30 June 2020, consistent with the F&A.

However, SA Power Networks has not incorporated the AER's preliminary decision as to the forecast closing RAB value at 30 June 2020 because SA Power Networks does not accept the AER's preliminary decisions in relation to:

- forecast capital expenditure; or
- regulatory depreciation.

12.5 Revised Proposal

SA Power Networks has calculated a revised RAB forecast for the 2015-20 RCP. This calculation uses the AER's RFM and PTRM and applies the same methodology as in the Original Proposal, but incorporates:

- our revised forecast capital expenditure (as detailed in Chapter 7 of this Revised Proposal); and
- our revised depreciation calculations (as detailed in Chapter 14 of this Revised Proposal).

In addition, the following assumptions that were made in our Original Proposal have been revised:

- forecast CPI escalation for the 2014/15 regulatory year has been updated with the actual CPI outcome;
- forecast capital expenditure for the 2014/15 regulatory year has been updated based on a forecast of expenditure for the year; and
- the estimated balance of work in progress at 30 June 2015 has been allocated to asset categories based on an updated analysis of its composition as at 31 March 2015.

The roll forward for SA Power Networks' RAB over the 2010-15 RCP is as set out in Table 12.1.

Table 12.1: SCS RAB roll forward to 30 June 2015 (nominal, $ million)

	2010/11	2011/12	2012/13	2013/14	2014/15
Opening RAB	2,900.0	3,096.8	3,287.9	3,502.0	3,674.4
Plus capital expenditure, net of contributions and disposals	271.0	325.7	335.2	291.3	335.4
Less straight line depreciation	(170.7)	(183.6)	(203.3)	(221.5)	(242.0)
Plus nominal actual inflation on opening RAB	96.6	48.9	82.2	102.6	48.9
Difference between actual and forecast capex for 2009/10					(38.3)
Closing RAB	3,096.8	3,287.9	3,502.0	3,674.4	3,778.4

The projected RAB for SCS at the end of each regulatory year over the 2015-20 RCP is as set out in Table 12.2.

The forecast capital expenditure included in Table 12.2 differs from the forecast capital expenditure included in the AER's Preliminary Determination because it is based on our revised forecast capital expenditure. Our revised forecast capital expenditure is discussed in Chapter 7 of this Revised Proposal.

The regulatory depreciation allowance included in Table 12.2 is higher than the depreciation allowance included in the AER's Preliminary Determination because of our revised forecast capital expenditure (which is offset slightly by our lower revised opening RAB) and the fact that we have applied a different depreciation methodology in this Revised Proposal. Our depreciation methodology is discussed in Chapter 14 of this Revised Proposal.

Table 12.2: SCS RAB roll forward to 2020 (nominal, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20
Opening RAB	3,778.4	4,057.5	4,347.1	4,598.2	4,819.8
Plus capital expenditure, net of contributions and disposals	436.5	471.4	459.1	455.2	429.1
Less straight line depreciation	(235.2)	(265.3)	(297.6)	(328.3)	(358.0)
Plus nominal actual inflation on opening RAB	77.8	83.6	89.6	94.7	99.3
Closing RAB	4,057.5	4,347.1	4,598.2	4,819.8	4,990.2

13. Weighted average cost of capital

In its Preliminary Determination, the AER did not accept SA Power Networks' proposed Weighted Average Cost of Capital (**WACC**) and gamma value.

The WACC comprises the return on equity and the cost of debt based on a 40:60 gearing using a benchmark efficient entity. The revenue building block derived from application of the WACC to the regulated asset base is also impacted by the inflation rate forecast for the RCP.

The gamma value determines the value of imputation credits and impacts the corporate income tax revenue building block.

13.1 Rule requirements

The determination of the rate of return is governed by section 6.5.2 of the NER.

In summary, these Rules require the rate of return to meet the rate of return objective 'that the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk' and further regard must be had to:

- relevant estimation methods, financial models, market data and other evidence;
- the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt;
- any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt; and
- in the case of return on equity, the prevailing conditions in the market for equity funds.

The determination of the cost of corporate income tax is governed by section 6.5.3 of the NER.

The AER must publish a Rate of Return Guideline that sets out the methodologies the AER proposes to use in estimating the allowed rate of return, in a way that is consistent with the rate of return objective.

13.2 SA Power Networks' Original Proposal

In our Original Proposal, we explained the reasons for adopting a different approach to that outlined in the AER's Rate of Return Guideline, in that our approach to:

- **return on equity** – adopted a multi-model approach to calculating the return on equity so as to comply with the NER requirements and to overcome the shortcomings in the AER's foundation model;
- **cost of debt** – adopted the AER's transition methodology for the trailing average cost of debt. However, in the subsequent submission process, SA Power Networks identified that the hybrid approach to determining cost of debt was more appropriate given the AER's release of how a benchmark efficient entity would have raised its debt; and
- **gamma** – was to use a value of tax imputation credits of 0.25 which was consistent with the 2011 decision of the Australian Competition Tribunal on this matter and which has been confirmed with more recent market evidence.

In our Original Proposal we proposed key parameters as shown in Table 13.1.

Table 13.1: Original Proposal WACC and Gamma parameters

WACC assumptions	Original Proposal
Nominal Risk Free Rate	3.46%
Nominal Pre-tax Cost of Debt	5.74%
Market Risk Premium	7.69%
Equity Beta	0.91
Post-tax Nominal Return on Equity	10.45%
Nominal Vanilla WACC	7.62%
Gamma	0.25

13.3 AER's Preliminary Determination

The AER did not accept SA Power Networks' calculation of the rate of return and substituted its own value for WACC and its constituent parameters. At a summary level, the AER's reasons in its Preliminary Determination reflect the following approach to return on equity, cost of debt, gamma, and inflation:

- return on equity – the AER applied its 'foundation model' approach, which is based on the Sharpe Lintner Capital Asset Pricing Model (**SLCAPM**). Some other models were used to inform the input parameter point estimates of the SLCAPM;
- cost of debt – for its estimate of cost of debt, it uses a method to transition from the 'on-the-day' approach used in the past to the 'trailing average' approach it now favours. Its preliminary decision estimate is for the first year of the RCP, and the rate of return will be updated annually. The return on debt estimate assumes a benchmark efficient entity issues debt with a 10 year term and has a BBB+ credit rating. The estimate of yield on this debt is derived from an average of data series from the Reserve Bank of Australia and Bloomberg;
- gamma – the AER makes an estimate of the value of imputation credits for income tax paid. It cites new evidence and advice that it has considered since its Rate of Return Guideline was published; and
- inflation – the AER uses the forecasts and mid-point targets of the Reserve Bank of Australia to derive an estimate of inflation.

The AER's preliminary decisions on these items are shown in Table 13.2.

Table 13.2: AER preliminary decisions on WACC and Gamma parameters

WACC assumptions	Preliminary Decisions
Nominal Risk Free Rate	2.55%
Nominal Pre-tax Cost of Debt	4.35%
Market Risk Premium	6.50%
Equity Beta	0.7
Post-tax Nominal Return on Equity	7.10%
Nominal Vanilla WACC	5.45%
Inflation rate	2.55%
Gamma	0.4

13.4 SA Power Networks' response to the Preliminary Determination

This Chapter of the Revised Proposal details SA Power Networks' proposals with respect to return on equity, cost of debt, gamma, and inflation. Before proceeding to these detailed proposals, we set out our high level response below.

SA Power Networks considers the AER's approach to setting the return on capital to be erroneous in relation to equity, debt and gamma.

The NER require a decision that sets an allowed rate of return that is commensurate with prevailing market conditions.[329] While real world equity returns have remained virtually constant, the AER's regulatory allowance has declined radically, in lock-step with unprecedented falls in base interest rates.

In the words of the Governor of the Reserve Bank of Australia, Mr Glenn Stevens, equity rates have not in reality followed the unprecedented downward movement in base rates:

> *'[A key] feature that catches one's eye is that, postcrisis, the earnings yield on listed companies seems to have remained where it has historically been for a long time, even as the return on safe assets has collapsed to be close to zero.'*[330]

[329] AEMC; *National Electricity Rules Version 71* (**The Rules**); Rule 6.5.2; pages 662-665.

[330] Reserve Bank of Australia; the World Economy and Australia Address to the American Australian Association luncheon hosted by Goldman Sachs, New York, USA (**RBA Speech**); 21 April 2015.

The key reasons for the mismatch between the allowance and commensurate market returns is firstly that the AER fails to correctly recognise the risk that SA Power Networks faces and inadequate compensation is provided for the risk it bears. Second, the AER fails to give any real weight to several of the key relevant finance models – contrary to the requirements of the Rules, to have regard to the insights arising from estimating all these models. The AER's approach relies on a single market factor to explain relative stock market returns despite more than 50 years of data suggesting that reliance on a single market factor is clearly incomplete. Furthermore, the AER implements its favoured 'SL-CAPM model' in an idiosyncratic way that causes the regulatory allowance to fluctuate more profoundly than observed equity returns as SA Power Networks moves through the economic cycle. Finally, even on a structural basis, that model delivers downwardly biased results for firms that are claimed to be 'low risk'.

Similarly, in the AER's preliminary decision for SA Power Networks' distribution determination (AER's Preliminary Determination) in respect of gamma, debt and estimating inflation, the AER's Preliminary Determination wrongly substitutes 'conceptual' estimations in place of real world market-based measures that benchmark efficient network businesses would face.[331]

Each of the aspects of the AER's Preliminary Determination needs to be amended so that the allowances are commensurate with market-based returns and in order for the regulatory allowance to foster efficient long-term investments necessary for the supply of safe and reliable electricity in the long-term interest of consumers, as required by the NEL.

For ease of reference, SA Power Networks' parameter value proposals are summarised in section 13.5. A complete discussion of our response to the AER's Preliminary Determination is contained in sections 13.6 – 13.11 that follow.

[331] AER; *Preliminary decision SA Power Networks distribution determination overview;* April 2015 (pdf version) (AER Preliminary Determination Overview); AER; *Preliminary decision SA Power Networks distribution determination*, Attachment 3 - Rate of Return; April 2015 (pdf version) (AER Preliminary Determination Attachment 3); AER; *Preliminary determination*, Attachment 4 - *Value of imputation credits*; April 2015 (pdf version) (AER Preliminary Determination Attachment 4).

13.5 Revised Proposal

For the reasons stated in this chapter of the Revised Proposal, as part of our revocation and substitution submission, we propose the following key parameters:

Table 13.3: Revised Proposal WACC and Gamma parameters

WACC assumptions	Revised Proposal
Nominal Risk Free Rate	2.55%
Nominal Pre-tax Cost of Debt	5.29%
Market Risk Premium	8.00%
Equity Beta	0.91
Post-tax Nominal Return on Equity	9.83%
Nominal Vanilla WACC	7.09%
Inflation rate	2.06%
Gamma	0.25

Our Revised Proposal:

- maintains the position in our Original Proposal concerning the allowed rate of return on equity (which delivers a return of 9.83%) and gamma (which should be 0.25);
- includes the 'hybrid' transition, also referred to as Option 4 in the AER's Preliminary Determination (which delivers a return of 5.29% using the 'place holder' averaging period); and
- reforms the way in which the inflation rate is determined by using actual recorded inflation for that part of the regulatory period that has already elapsed and otherwise market based measures instead of the forecasts and mid-point targets of the Reserve Bank of Australia.

As indicated above, these matters are discussed in detail in the sections on return on equity (Sections 13.6 and 13.7), cost of debt (Sections 13.6 and 13.9), gamma (Sections 13.6 and 13.8), and inflation (Sections 13.6 and 13.10).

In Section 13.11, we summarise why our Revised Proposal on these parameters will contribute towards a materially preferable NEO decision.

13.6 Rule requirements

13.6.1 All components must comprise a consistent, prevailing market-based return that the benchmark firm would actually face (and can replicate) in the 2015-20 RCP

Key parts of the AER's regulatory determination process are the decisions concerning the allowed rates of return for equity[332] and debt; [333] the estimate of gamma; [334] and the estimate of inflation. [335] Despite contrary assertions by the AER's economic consultants when discussing the gamma parameter,[336] these constituent decisions are closely connected with each other because together they determine the return that investors in the business can earn on the capital that the regulated business requires from them.

The AER must publish, and has published, a Rate of Return Guideline (**Guideline**) that addresses the issues that determine the rate of return on capital. Specifically the Guideline must set out:

> '1) *the methodologies that the **AER** proposes to use in estimating the allowed rate of return, including how those methodologies are proposed to result in the determination of a return on equity and a return on debt in a way that is consistent with the allowed rate of return objective; and*
>
> 2) *the estimation methods, financial models, market data and other evidence the **AER** proposes to take into account in estimating the return on equity, the return on debt and the value of imputation credits referred to in rule 6.5.3.'*[337]

The substantive requirements are for the AER's decision to deliver efficient market based (not conceptual) assessments for each of these components using the best available information on the current effective financing costs for the benchmark efficient entity:

> 'b) *The allowed rate of return is to be determined such that it achieves the allowed rate of return objective.*
>
> c) *The allowed rate of return objective is that the rate of return for a Distribution Network Service Provider is to be **commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk** …*
>
> 'e) *In determining the allowed rate of return, [regard must be had] to:*
>
> 1) *relevant estimation methods, financial models, market data and other evidence;*
>
> 2) *the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and*

---

[332] Clause 6.5.2(g) of the NER.
[333] Clause 6.5.2(i) of the NER.
[334] Clause 6.5.3 of the NER.
[335] Clause 6.4.2(b)(1) of the NER.
[336] Handley J; Advice on the NERA Report: Estimating Distribution and Redemption Rates for the Australian Energy Regulator; 20 May 2015.
[337] Clause 6.5.2(n) of the NER.

3) any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.

…

g). In estimating the return on equity under paragraph (f), regard must be had to the ***prevailing conditions in the market for equity funds.***

…

j) Subject to paragraph (h), the methodology adopted to estimate the return on debt may, without limitation, be designed to result in the return on debt reflecting:

1) the return that would be required by debt investors in a benchmark efficient entity if it raised debt at the time or shortly before the making of the distribution determination for the regulatory control period;

2) the average return that would have been required by debt investors in a benchmark efficient entity if it raised debt ***over an historical period prior to the commencement of a regulatory year in the regulatory control period;*** *or*

3) some combination of the returns referred to in subparagraphs (1) and (2).

k) In estimating the return on debt under paragraph (h), regard must be had to the following factors:

…

4) any impacts (including in relation to the costs of servicing debt across regulatory control periods) on a benchmark efficient entity referred to in the allowed rate of return objective that could arise as a result of changing the methodology that is used to estimate the return on debt from one regulatory control period to the next.' [338]

'γ is the value of imputation credits.' [339]

'[Use should be made of] a method that the AER determines is likely to result in the best estimates of expected inflation.'[340]

As detailed in this Revised Proposal, in relation to each of the AER's preliminary decisions in relation to the rate of return, SA Power Networks is concerned that the AER fails to accommodate the contemporaneous market-reflective return that the benchmark firm would actually bear in efficient capital markets. Specifically:

- with respect to equity, the AER's approach of significantly under-stating the degree of risk we face combined with a very long run market risk premium with an extremely short run base interest rate delivers an allowed rate of return on **equity** clearly below the prevailing hurdle rates for our industry. The Reserve Bank has now explained that the required return on equity has been relatively stable over recent months as the equity risk premium has increased to offset the material decline in base interest rates. [341] The AER's Preliminary Determination fails to give any real weight

[338] The Rules; Rule 6.5.2; pages 662-665.
[339] The Rules; Rule 6.5.3; page 665.
[340] Clause 6.4.2(b)(1)
[341] RBA Speech.

to three of the four models that it has acknowledged are relevant. The AER must reflect these facts in its decisions;

- with respect to **gamma**, the AER's approach eschews estimates of gamma drawn from contemporaneous equity markets in favour of a 'conceptual analysis'. [342] This imposes an artificial estimate that is substantially higher than any benchmark efficient entity would experience when seeking to raise capital in the real marketplace and does not represent the 'value of imputation credits';[343]
- with respect to the **allowed return on deb**t, the AER acknowledges that the benchmark efficient entity would have a portfolio of long term debt with a staggered portfolio of issuance and maturity. [344] However, the AER's approach would depress the allowed return below the level of costs associated with such a staggered portfolio in order to claw-back allegedly inflated gains from the immediately prior period. These gains, to the extent that they exist, can only have resulted from the previous lottery-like system of selecting debt allowances for the whole five year RCP over extremely short averaging windows in volatile debt markets; and
- with respect to **inflation**[345] we provide evidence that the relevant measure should be a weighted average over a 5 and 10 year horizon and that to the extent that the Final Determination occurs within a RCP that has already commenced, some actual inflation statistics should be used rather than forecasts. Further, strong evidence has emerged that the approach of relying on RBA forecasts and its statutory targets is not delivering a good estimate of inflation. The problem arises in particular with the use of RBA targets in the 'out years'. The issue with the use of the targets as an estimate of inflation is that central banks in Australia and around the world acknowledge that the instruments at their disposal are not succeeding in overcoming the prevailing deflationary forces. In essence, neither markets nor the central banks themselves expect these targets will be met. Meanwhile there is strong evidence that liquidity has returned to the markets for indexed bonds and it is now appropriate for the AER to revert to using this as the best measure of inflation.

All of these features of the AER's preliminary decision are contrary to the requirements of the Rules extracted above in that they result in a significant diversion between the regulated allowances and the efficient financing costs in the prevailing market conditions.

13.6.2 Inter-period look-backs or claw-backs are impermissible

With respect to the allowed return on debt, the AER's approach involves a departure from the prevailing financing costs of a benchmark efficient entity (given that it would have a portfolio with staggered debt issuance). It further explicitly seeks to impose an inter-period 'look-back' when setting the allowance. Under-compensating SA Power Networks now, in order to reverse alleged past 'windfall gains' is contrary to the express language of the Rules. It is also inconsistent with the basal principles of the economic regulatory system upon which the national electricity network are based.

The Australian economic regulatory system is an 'incentive based' system known as 'CPI-X' regulation. That system was based upon the 'RPI-X' system initially developed by the UK's Royal Treasury for the regulation of British Telecom in the 1980s. The key aspect of this system is that, subject to well defined carry-over mechanisms, the business is allowed to earn an efficient contemporaneous benchmark return. The business can profit by out-performing the benchmark or suffer losses where it under-performs the benchmark. Except to the limited extent of a well-defined incentive carry-over

---

[342] AER *Preliminary Determination* Attachment 4.
[343] Ibid.
[344] AER *Preliminary Determination* Attachment 3.
[345] This issue has only recently become apparent and it was not discussed in SA Power Network's Original Proposal. We are not, of course, critical that the AER's Preliminary Determination did not address this issue but it will certainly be necessary for the Final Determination to give full effect to the evidence that has now emerged that the inflation forecasts used in the AER's Preliminary Determination result in returns that are well below the level that would be commensurate with the returns expected by a benchmark efficient entity.

mechanism, at the time of each regulatory determination, the question of whether the business out-performed or under-performed the benchmark is not a relevant consideration.

In this regard, SA Power Networks is particularly concerned that the AER's Preliminary Determination seeks to 'claw back' alleged past wind-fall gains on past debt allowances by under-compensating the business relative to the AER's own current assessment of the efficient debt financing costs. This issue is discussed further below at Section 13.9.3.

13.6.3 The decision making test

SA Power Networks is concerned that, in a number of respects, the AER's Preliminary Determination has applied confused and incorrect decision making tests. In most instances, these tests appear to be hang-overs from former regulatory arrangements that the AEMC deliberately and expressly repealed.

In the past:

- The SL-CAPM was required when regulating electricity networks and strongly encouraged for the gas networks. However, now, *due regard must* be had to all the relevant models. [346] We are concerned that the AER's approach is to start from the proposition that the SL-CAPM is the incumbent model and, no matter how strong the case, it cannot be departed from.
- The gas industry was previously regulated under a 'propose and respond' approach under which the AER's task was to assess whether the network business' proposal was unreasonable before substituting its own position. Now the AER must reach the best decision on all the available material – including submissions made by the business itself (as SA Power Networks did in relation to the allowed return on debt).
- For electricity, previously the Rules required the AER to apply its Statement of Regulatory Intent unless there was 'persuasive evidence' to depart from the position in that document. Now, however, the requirement is simply to make the decision that best promotes the rate of return objective whether or not that position was set out in the Guideline. [347] However, in a number of respects the AER's Preliminary Determination seeks to impose a substantial (and in some cases impractically high) hurdle upon the business' claims rather than setting the allowance on the best available information.

In 2011,[348] before the AEMC put the current Rules in place, the AER obtained a report from Kevin Davis of the University of Melbourne that asserted that each of the Black-CAPM, Fama French Model and DGM were not superior to the SL-CAPM. Specifically Davis stated:

> *'It is my opinion that (i) the Black-CAPM does not resolve the problems of the Sharpe CAPM; (ii) it is not better supported than the Sharpe CAPM by available empirical evidence; (iii) its implementation is problematic because of problems in reliably estimating the zero beta return. It is my opinion that (i) the Fama French model cannot resolve theoretical issues in asset pricing because its foundations are empirical rather than theoretical; (ii) the empirical question of model's superiority over the Sharpe CAPM (or other asset pricing models) remains contested; (iii) it would be possible to implement the Fama French model in Australia, but the studies which have done so to date have found conflicting results which do not, in my opinion, provide strong support for its use. It is my opinion that the Dividend Growth Model is not superior to the Sharpe CAPM for estimating the cost of equity for an individual firm neither on theoretical ground nor on available empirical evidence, and that there are sufficient difficulties in its*

---

[346] The Rules; Rule 6.5.2(e)(i); page 663.
[347] AER; Better Regulation, *Rate of Return Guideline*; December 2013 (pdf version) (The Guideline).
[348] Davis also drafted a report in May 2011 to similar effect.

application to limit its use as to best 'ballpark' estimation at an aggregate market level.'[349]

The purpose of this report was to support a conclusion under the former National Gas Rules that the AER would continue to use the SL-CAPM. Under those rules a single 'well accepted' model was required.

The AEMC expressly rejected that approach when re-drafting the Rules because:

(a) selecting a single model excludes the useful contributions that other models can make; and

(b) the notion of the model being 'well accepted' creates a bias towards conservatism instead of seeking the result that best achieves the rate of return on the state of the current science.

These previous approaches have now been superseded. When construed in the context of the regulatory instruments, the task at hand and the case law,[350] the decision making test is required to take into account all of the relevant models and other inputs (which quite clearly must include fully estimating each model), and to give *due weight* to each of these inputs in reaching a decision that best promotes the rate of return objective.

The AER's 'Foundation Model', with minor alterations, is a continuation of the 'Davis-based' Envestra decision and as such is unacceptable under the current Rules.

SA Power Networks' Original Proposal was established on the basis of the requirement to take account of all of the relevant models, as is our Revised Proposal as explained below.

13.7 Return on Equity

13.7.1 SA Power Networks' Original Proposal

The two predominant themes of SA Power Networks' Original Proposal have effectively been ignored in the AER's Preliminary Determination:

- Electricity network businesses face a completely changed risk profile in very recent times due to the rapid advance in disruptive technologies. As a consequence of this, investors require returns that sit several rungs higher on the ladder of efficient risk-adjusted returns; and
- The AER's approach to setting equity returns using its implementation of the SL-CAPM as a foundation model has moved sharply downward as base interest rates have fallen. This is despite the fact that equity markets are demanding returns that are not significantly altered compared with pre-crisis levels. Notably, a multi-model approach would not suffer from this flaw.

Changed Risk Profile

In particular, our proposal detailed the very rapid rise in solar PV penetration in our network. Solar PV panels are now inexpensive (following a period of significant European incentives that resulted in manufacturers, particularly in China, building massive low cost production plants). We pointed out that enormous investments were pouring into battery storage research and development and that if (as predicted by many) storage technology followed a similar trajectory to that of solar PV, it could

---

[349] Davis K*; Cost of Equity Issues*: *A report for the AER*; Kevin Davis Research Director Australian Centre for Financial Studies, Professor of Finance, the University of Melbourne; January 16, 2011.
[350] Re Dr Ken Michael AM; Ex parte EPIC Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231.

quite likely become similarly attractive to a significant number of customers. These developments, combined with smart technology that assists in managing domestic power production and consumption, bring into question the assumption that an electricity network business will, in all circumstances, be able to recover long run costs from customers or whether a significant number of customers might decide to substantially reduce their use of the network or disconnect from it entirely.

Relevant Models and Inputs

Our proposal then established an allowed rate of return for risk adjusted equity based on advice from Gray and Hall by fully estimating each of the four financial models that both we and the AER agree are the relevant models to consider and taking a weighted average of these measures with due weight being ascribed to each financial model.[351] When specifying the SL-CAPM, we used the mid-point between the Wright and Ibbotson approaches[352] for estimating the Market Risk Premium. Taking the midpoint of these approaches acknowledges that the true relationship between base interest rates and equity risk premiums is likely to be somewhere between the two theoretical extremes of a perfect offsetting relationship (which would imply a constant required return on equity) and no relationship at all (which would imply a constant MRP).

On this basis, our allowed rate of return for equity was to be 10.45%.

13.7.2 AER's Preliminary Determination

Risk Profile

The AER's Preliminary Determination dismissed SA Power Networks' analysis of risk. Although the AER acknowledged that the risk we face has significantly risen in the very recent past, it declined to make any adjustment (to the allowed return, to cash flows, or to depreciation schedules) claiming that the shortest end duration of its beta studies (ie studies over five years) should reflect these emerging risks.

No consideration was given to the fact that:

1) the most recent of these five year studies pre-dated most of the developments detailed in our Original Proposal;
2) an up to date five year study would dilute the measure of these new risks in an average that partly pre-dates these developments;
3) the AER's method is to blend the consideration of short duration studies with much longer duration studies which further dilutes the measurement of new risks; and
4) the majority of the firms that the AER takes to be comparators are not electricity network businesses.

Relevant Models and Inputs

The AER effectively sets aside the warnings that the regulatory system is significantly under-estimating the level of risk facing a benchmark firm. It then adopts an over-simplifying and outdated regulatory approach, comprising the use of the SL-CAPM model (further discussed below) and a downward trajectory for the beta used in that model to a previously un-plumbed depth of 0.7.

---

[351] SFG Consulting; *The required return on equity for regulated gas & electricity network businesses*; Report for Jemena Gas Networks, ActewAGL Distribution, Ergon ,Transend and SA Power Networks; 6 June 2014; paragraph [28]; page 10.
[352] SA Power Networks, *Regulatory Proposal 2015-20*, page 218.

The AER's Preliminary Determination rejected our proposal of using a weighted average of the four predominant relevant models and instead continued the outdated approach of using the SL-CAPM. The AER's approach is to estimate three parameters, insert them into the SL-CAPM formula and then to adopt the output from that formula as the allowed return on equity. Without making any explicit adjustment to the SL-CAPM, the AER's only recognition of the other models is to augment its traditional approach to rationalising the selection of beta and MRP with discussion that includes an idiosyncratic treatment of two of the financial models that the AER has refused to use directly in estimating the return on equity.

In our Original Proposal, we explained why, in the context of Rule 6.5.2 of the NER, to correctly 'have regard to relevant [inputs]' one must give them real and due weight in the final decision. This standard is not met by considering and then disregarding and giving no weight to an input.

On *any* reading of the term 'have regard' in Rule 6.5.2, the standard cannot be met by merely dismissing a relevant model (such as the Fama French model) without even specifying it and considering the results delivered.

Nevertheless, without estimating three of the financial models the AER acknowledges are relevant, the AER's Preliminary Determination persists with a preference for SL-CAPM:

- using two of the models in ways that are inconsistent with their inherent features as one of the many ways to 'inform' the selection of parameters within the SL-CAPM (ie the DGM and Black CAPM):
  - The AER's Preliminary Determination asserts that the DCF model has been used to inform its estimate of the MRP implying that this is a recognised approach to using the model. However, that model is in fact designed to be used to estimate the required return on equity and that is how it is applied in the US. The AER disregards this standard application of the approach entirely; and
  - Similarly, the AER's Preliminary Determination asserts that the Black-CAPM has been considered in selecting the value for beta but again there is no recognised usage of the Black-CAPM in that way; and
- disregarding the third one completely (ie the Fama French model).

We presented detailed empirical work to demonstrate that this approach is inappropriate. Other regulators who use the SL-CAPM amongst the inputs to the return on equity (such as the Public Utilities Commissions in the US) have made upward adjustments to reflect the empirical evidence that the SL-CAPM performs badly and, notably, gives a <u>structural</u> under-estimate of the returns earned by low beta stocks.

A further cyclical reason explains why the AER's approach is delivering record under-estimates of the required rate of return. There is a serious mis-match between prevailing equity returns and the AER's regulatory allowance. The AER's Preliminary Determination has continued to adopt the Ibbotson inspired implementation of the SL-CAPM, in which a contemporaneous measure of base interest rates is combined with a long run MRP – simply stated, the approach mixes apples and oranges.

While this effect is cyclical, it is notable that this particular low-point in base interest rates is the lowest since the Second World War.

Recent speeches by the Governor of the Reserve Bank and his deputy have focused on the phenomenon that while base rates have fallen, market measures of the prevailing required equity returns have *not* fallen and instead have remained at almost pre-crisis levels:

'Unfortunately, … the legacy of the 2008 crisis is yet behind us. From the vantage point of most central banks, the world could hardly, in some respects, look more unusual.

…

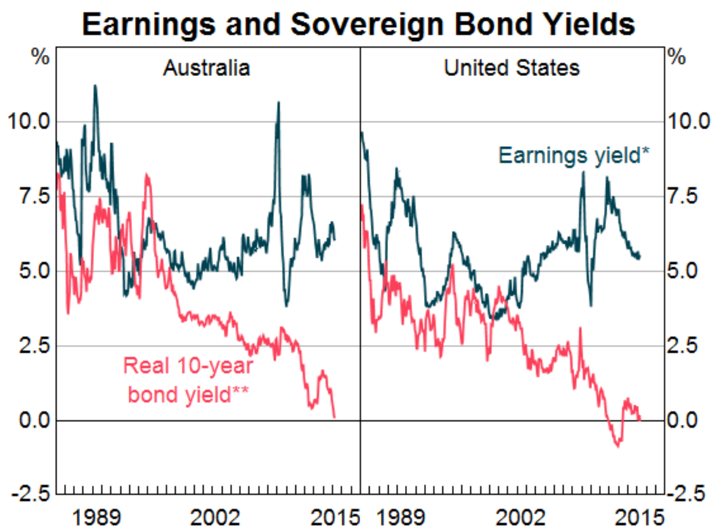
Policy rates in the major advanced jurisdictions have been near zero for six years now.

…

[A key] feature that catches one's eye is that, postcrisis, the earnings yield on listed companies seems to have remained where it has historically been for a long time, even as the return on safe assets has collapsed to be close to zero (Graph 2). This seems to imply that the equity risk premium observed ex-post has risen even as the risk-free rate has fallen and by about an offsetting amount.

…

Graph 2



* Trailing earnings-to-price ratio for the MSCI Australia and S&P 500 indices

** Prior to 1996 for Australia and 2000 for the United States, 10-year sovereign yields are deflated using underlying inflation

Sources: ABS; Bloomberg; Board of Governors of the Federal Reserve System; MSCI; RBA; Thomson Reuters; Yieldbroker

[T]he hurdle rates of return that boards of directors apply to investment propositions have not shifted, despite the exceptionally low returns available on low-risk assets.

The possibility that, de-facto, the risk premium being required by those who make decisions about real capital investment has risen by the same amount that the riskless rates affected by central banks have fallen may help to explain why we observe a pickup in financial risk-taking, but considerably less effect, so far, on 'real economy' risk-taking.'[353]

[353] RBA Speech.

The above speech provides a compelling rationale as to why the AER must change its approach and, as we explain below, a multi-model approach does not suffer to anywhere near the same extent from these problems.

The staff of the RBA (Lane and Rosewall) have published a more detailed analysis. They state:

> *'Liaison and survey evidence indicate that Australian firms tend to require expected returns on capital expenditure to exceed high 'hurdle rates' of return that are often well above the cost of capital and do not change very often. In addition, many firms require the investment outlay to be recouped within a few years, requiring even greater implied rates of return. As a consequence, the capital expenditure decisions of many Australian firms are not directly sensitive to changes in interest rates.*[354]
>
> *…*
>
> *[C]ontacts note that the hurdle rate is often held constant through time, rather than being adjusted in line with the cost of capital. Regardless of whether changes in interest rates have a* ***direct*** *effect on investment decisions, interest rates will still have a powerful* ***indirect*** *influence on firms' investment decisions through other channels, including their effect on aggregate demand.'*[355]
>
> *'Many liaison contacts also report that hurdle rates are not changed very often and in some instances have not been altered for at least several years. These observations are also reflected in the recent survey by Deloitte; two-thirds of corporations indicated their hurdle rate was updated less frequently than their formal review of the WACC, and nearly half reported the level of their hurdle rate was changed 'very rarely' (Graph 4). For these firms, changes in interest rates do not flow through to hurdle rates; rather, the margin between the WACC and the hurdle rate changes. One-third of firms said they update their hurdle rate when they review their WACC, which is possibly on a quarterly or annual basis; other contacts in the liaison program have also noted the WACC used in investment decisions is similarly reviewed infrequently.*
>
> *Liaison contacts have provided several reasons why the hurdle rate may not be sensitive to the cost of capital. A common observation is that the true cost of equity, and therefore the overall cost of capital, cannot be observed.*[356] *Managers have also noted that changes in the observed cost of debt owing to changes in interest rates are likely to be temporary, and so they are reluctant to react to developments that may soon be unwound. A few business contacts have argued that keeping the hurdle rate constant acts as an automatic time-varying risk adjustment: interest rates tend to be low when uncertainty is high, so the gap between the hurdle rate and the cost of capital should be higher (and vice versa).'*[357]

Further, because the AER relies heavily on a single model rather than taking a blended approach, and because it uses only the simplest of the capital asset price models available, there is a higher likelihood of divergence between the AER's estimates and the return on equity that investors require.

[354] Kevin Lane and Tom Rosewall; '*Firms' Investment Decisions and Interest Rates'* (2015) June Quarter Bulletin; page 1.
[355] Ibid; page 2.
[356] In general, managers of listed firms appear to use the capital asset pricing model (CAPM) as their primary measure of the cost of equity. Similar results have been found for US and European firms (Graham and Harvey 2001; Brounen, de Jong and Koedijk 2004). As several liaison contacts have noted, the cost of equity implied by CAPM will be sensitive to the estimation sample period and method. In addition, other measures of the cost of equity could provide different results.
[357] Kevin Lane and Tom Rosewall; '*Firms' Investment Decisions and Interest Rates'* (2015) June Quarter Bulletin; pages 3-4.

The AER's Preliminary Determination culminates in an allowed rate of return for equity in the prevailing market conditions that is well below that which would be commensurate with the efficient financing practices of a benchmark efficient entity.

13.7.3 SA Power Networks' response to AER Preliminary Determination

We remain of the view that the approach to establishing the allowed return on equity that was set out in our Original Proposal is correct and a materially preferable approach to that which appears in the AER's Preliminary Determination. Indeed it is necessary for the AER's Preliminary Determination to be revoked and substituted in this respect for the Final Determination to accord with the rate of return objective in the NER.

(a) The evidence upon which our submission is based

Although the AER did not adopt the suggestions of the original expert reports that we submitted in support of our proposal, these should be reconsidered by the AER before making the Final Determination. They provide a thorough analysis of why the 'multi-model' approach is preferable to the 'foundation model' approach. In many cases, the AER has not properly recognised the insights they provide into equity markets generally and the flaws in the AER's approach in particular.

Since SA Power Networks' Original Proposal and before the AER's Preliminary Determination was published, SA Power Networks jointly procured the following additional reports that support SA Power Networks' Original Proposal:

1) NERA; Review of the Literature in Support of the Sharpe-Lintner CAPM; the Black CAPM and the Fama-French Three-Factor Model, March 2015, Attachment M.2. This report discusses material previously before the AER and provides a thorough investigation of consideration by a wide range of experts on models identified in the Guideline as those models to which the AER will have regard in identifying the return on equity.
2) SFG Consulting; The foundation model approach of the Australian Energy Regulator to estimating the cost of equity; March 2015, Attachment M.3. This report by Gray and Hall details a series of evidence that demonstrates that the 'Foundation Model' is significantly flawed. This evidence even includes some aspects of the material that the AER's own expert, Handley, presents.
3) SFG Consulting; The required return on equity for the benchmark efficient entity; February 2015, Attachment M.4. This report by Gray and Hall considers a range of criticisms that the AER and its consultants make in relation to Gray and Hall's multi-model approach. This report answers these criticisms and finds that there is no reason to depart from their original multi-model approach.
4) NERA; Historical Estimates of the Market Risk Premium; February 2015, Attachment M.5. This report by Wheatley explains when geometric averages are inappropriate where the AER's regulatory arrangements do not provide for compounding. This report also investigates the flawed adjustment that Brailsford, Handley and Maheswaran rely on and reiterates that their approach is flawed.
5) NERA; Empirical Performance of the Sharpe-Lintner and Black CAPM; February 2015, Attachment M.6. This report by Wheatley undertakes a 'state of the art' empirical analysis of the performance of the SL-CAPM (as implemented by the AER) the Black-CAPM and a 'naive model' in which no adjustment is made to risk. This report demonstrates that the AER's SL-CAPM performs even worse than the 'naive model'. By contrast the Black-CAPM performs comparatively well.

6) SFG Consulting; Beta and the Black Capital Asset Pricing Model; 13 February 2015, Attachment M.7. This report by Gray and Hall assesses the best estimate of beta to be 0.82, applicable to both the SL-CAPM and the Black-CAPM. Additionally it calculates the best estimate of the zero-beta premium for use in the Black-CAPM to be 3.34%. The report also identifies an estimate for beta of 0.91 for use in the SL-CAPM if that model is to be the only one used.

7) SFG Consulting; Using the Fama-French model to estimate the required return on equity; February 2015, Attachment M.8. This report by Gray and Hall comprehensively responds to the AER's stated reasons for excluding the Fama French model from being used in calculating the allowed rate of return for equity.

8) SFG Consulting; Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network; 18 February 2015, Attachment M.9. This report by Gray and Hall examines a range of issues as to how to implement the DGM in Australia, correcting some misconceptions of the AER in relation to implementing the DGM.

9) Letter from Grant Samuel & Associates Pty Limited (**Grant Samuel Letter**) to the Directors of Transgrid; 12 January 2015, Attachment M.10. This letter vigorously disputes the use to which the AER has put Grant Samuel's Envestra Report and refutes the AER's assertions that practitioners do not commonly use the DGM or Fama French style adjustments to the capital asset pricing model.

10) Incenta Economic Consulting; Further update on the required return on equity from Independent expert reports; February 2015, Attachment M.11. This report corroborates Grant Samuels' views as the usual approach of finance professionals to capital asset pricing models.

These reports were lodged by other businesses with the AER prior to the AER's Preliminary Determination but they have not yet formed a formal part of our submissions. In a significant number of cases this material was before the AER at the time of our Preliminary Determination as part of the decisions being made by the AER for the NSW and ACT electricity distribution determinations and the Jemena Gas Networks determination.

However, there are quite a number of instances in which the AER has failed to engage with the details of these experts' work and the significance of their conclusions as a combined 'sounding of the alarm' that from a theoretical and empirical perspective the foundation model approach is seriously out of step with the prevailing cost of equity.

In particular, it is difficult to understand how the AER can continue to adhere to the 'foundation model' SL-CAPM based approach in light of NERA's literature review concerning the theoretical flaws of the SL-CAPM and the model's poor performance as detailed in NERA's empirical testing (see reports 1 and 5 in the above list). It is also concerning that in light of the requirement in the Rules to have regard to all the relevant models 'relevant estimation methods, financial models, market data and ***other evidence'***, the Preliminary Determination asserts that the well founded adjustments that Incenta Economic Consulting recommend could possibly be beyond power. It is important for the AER to re-consider and fully engage with all the material in the above reports and to make changes to its approach in response to the findings in those reports.

Additionally, since that time, we have procured the following reports:

1) A report by the authors of Frontier Economics' 2013 report for the AER concerning the analysis of risk. As detailed in the report and summarised below, the AER has mis-interpreted the original 2013 report in key respects and this has significantly contributed to erroneous conclusions

concerning the quantum and nature of the risks our business carries. This report also explains that the level of risk has significantly increased since 2013.[358] (refer Attachment M.13)

2) A report by Professor Gray and Dr Hall ('**Gray and Hall'**), now of Frontier Economics who analyse all the key flaws with the AER's Preliminary Determination's approach to setting the allowed rate of return for equity. (refer Attachment M.12)

3) A report by NERA; The Cost of Equity: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, and for Jemena Gas Networks, A report for ActewAGL Distribution, AGN, APA, AusNet Services, CitiPower, Energex, Ergon Energy, Jemena Electricity Networks, Powercor, SA Power Networks, and United Energy; June 2015, Attachment M.14. Mr Wheatley addresses criticisms that have been made by the AER's consultants of his previous work. As is evident from his report, the AER's consultants have failed to give any material consideration of, or have regard to, the key points previously presented by Mr Wheatley and submitted to the AER.

4) A report by NERA; Further Assessment of the Historical MRP: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, A report for United Energy, June 2015, Attachment M.15. Again, Mr Wheatley's previous work has been given an inadequate and superficial consideration by the AER's consultants. In addition, Mr Wheatley has undertaken a detailed reconciliation between the analysis prescribed in his previous reports with the original Lamberton dividend yield series which the AER regards as important.

5) A report by Dr Robert Malko, a leading US regulatory professional who has been working as a specialist on energy regulation since the 1970s and whose report is significant in three main respects – it shows that the DCF can be used very effectively in energy regulation; that US regulators do commonly use an Empirical CAPM that is to the same effect as the Black CAPM and why the multi-model approach is strongly preferable to a single or foundation model approach.[359] (refer Attachment M.16)

6) A witness statement by Ronald L. Knecht, the Chief Fiscal Officer for the State of Nevada in the US who is an experienced former energy regulator who has consistently used the Fama French Three Factor Model in his work. He states that while there is still some apprehension about the use of the Fama French Three Factor Model, it has been recognised in at least three states, Massachusetts, Delaware and Nevada, in conjunction with other models to produce an arithmetic mean as an estimate. He further states that the Fama French Three Factor Model is valuable and should receive consideration along with other models. (refer Attachment M.17)

7) SFG Consulting; Updated estimate of the required return on equity, Report for SA Power Networks; 19 May 2015. This report by Gray and Hall provides an update to previous reports on the basis of new data, in particular an updated estimate of the risk free rate based on the 20-day averaging period beginning on 9 February 2015. (refer Attachment M.18)

8) Frontier Economics; Cost of equity estimates over time, June 2015, Attachment M.12. This report illustrates how the AER's approach to estimating the cost of equity is both lower than alternative measures and volatile, moving in lock step with movements in the prevailing yields on Commonwealth Government Securities.

In particular, Frontier has reviewed all the material that the AER has now generated in support of its 'Foundation Model' approach and identified four key issues.

Firstly, the AER's approach fails to have regard to all of the relevant material and proceeds as if there had been no amendment to the NER in 2012.

---

[358] Frontier; *Review of the AER's conceptual analysis for equity beta,* report prepared for ActewAGL Distribution, AGN, AusNet Services, Citipower, Ergon, Energex, Jemena Electricity Networks, Powercor Australia, SA Power Networks and United Energy; June 2015.
[359] Malko, JR; *Statement;* 16 June 2015 (**Malko**).

Secondly, although the AER's documents refer to a broad range of materials, the 'Foundation Model' approach imposes arbitrary binding constraints that severely limit or prevent these other inputs being given weight according to their own terms.

Thirdly, the AER has, in several instances, failed to recognise that contradictions before them logically requires them to make a decision of which of the contrary evidence is correct and which is incorrect. Instead the AER appears to take the position that choosing from the bottom range of material through top range of material (and any value in between, where such values are not supported by any material) rather than correctly identifying which among the conflicting evidence is to be preferred.

Finally, the report highlights how very inappropriate it is for the AER to continue to give the SL-CAPM a position of primacy when it demonstrably fails to address issues that other models successfully address.

(b) *Analysing the level of risk our business faces*

The AER should wholly re-work its analysis of risk. The AER's Preliminary Determination analysis is based in significant part on a report the AER commissioned from Frontier Economics. Frontier Economics has now reviewed the use to which its work has been put by the AER. It relevantly states:

> *'The fact that the precise relationship between leverage and equity beta is not known with certainty does not mean that the effect of leverage on beta should be disregarded when making comparisons between estimated equity betas. Such an approach would be at odds with accepted finance and regulatory practice.*
>
> *The 'financial risks' that we considered in our 2013 report for the AER are not the same as financial leverage and do not substitute for the leverage component of equity beta. The AER appears to have misunderstood this point in our 2013 report.'*
>
> *'The evidence that the AER presents in relation to US utility betas supports a re-levered equity beta estimate of close to 1.'*[360]
>
> *'There have been developments in the roll-out and adoption of disruptive technologies since our 2013 report. There is more uncertainty about the future of the industry now than there was even two years ago, and it is not unreasonable to think that investors would take this into account when allocating scarce capital to this industry.*
>
> *The AER suggests that any systematic component of disruptive technology risk would be captured in its equity beta estimates. Our view is that this is very unlikely.*
>
> *The AER suggests that to the extent that the risks are non-systematic in nature, those risks would more appropriately be compensated through regulated cash flows (such as accelerated depreciation of assets). However, notwithstanding that the AER recognises that disruptive technologies may increase the risks faced by NSPs, the AER has made no allowances for these risks either through the rate of return or through regulated cash flows.'*[361]

As clearly evidenced by this additional work, the AER has failed to properly recognise the effect of a 60% leverage on the beta. Even if our business did have a low operating risk the AER has failed to

[360] Frontier; *Review of the AER's conceptual analysis for equity beta*; paragraph [10]; page 2.
[361] Ibid; [11]; page 3.

correctly recognise the effect of the 60% leverage on the equity beta. As discussed below, our business must not be regarded as a business that has low operating risk.

The correctness of our initial submissions concerning the substantial change in the risk profile we face has been borne out by developments that have occurred since that time. Even in the short time since our Original Proposal significant additional advances have been made in exactly the way our Original Proposal predicted – substantial reductions in battery storage costs are resulting from significant technological advancement and entrepreneurial investments. On 2 March 2015, InDaily reported that:

> *'Zen Energy Systems, which specialises in solar, says its new battery technology has attracted the attention of major developers who see an opportunity to avoid expensive connection to the mainstream electricity network.*
>
> *…*
>
> *Advocates argue that taking smaller communities off the main transmission network could reduce costs for all users, by reducing inefficiency in the system.*
>
> *Zen chief executive Richard Turner told a joint Planning Institute/ Engineers Australia seminar recently that new technology meant 'micro grids' were a real option for small towns and new housing developments.*
>
> *Turner said he was studying the feasibility of removing SA towns from the electricity network using a combination of roof-top solar, wind energy and other options such as co-generation (where heat from an existing industrial process is used to generate power).*
>
> *…*
>
> *Turner is preparing to offer a battery to the domestic market which can store excess energy produced by solar systems for use in the evening.*
>
> *A product for off-grid use in regional and remote areas is already on the market. The 10kwh 'Urban Powerbank' – the size of a domestic fridge – is likely to be on the market mid-year.*
>
> *…*
>
> *'Interestingly enough we are having many housing developers coming to us for new housing estates saying – 'look can you take me through all the options … right through to taking the whole development off the grid'.*
>
> *…*
>
> *'We're talking to probably half a dozen major developers around the country who have housing developments of two, three, four thousand homes, talking about some sort of hybrid network alternative. Really interesting times there.*
>
> *…*
>
> *State Energy Minister Tom Koutsantonis told InDaily that localised generation was a good option for the future of regional towns and for individuals to save costs.*
>
> *'With one in four household customers in SA now using solar PV systems and as energy storage devices such as batteries reduce in cost, there is enormous potential for customers to offset their electricity usage and, in future, be serviced by more localised generation and energy storage,' he said.'*[362]

[362] See InDaily; *Developers want housing estates off grid*, 2 March 2015; http://indaily.com.au/news/2015/03/02/developers-want-housing-estates-off-grid/

On 4 May 2015 Business Spectator reported that Tesla had released a battery storage product.[363] Similarly on 5 May 2015 InDaily reported that Tesla had released a home-use power storage device that was gaining a great deal of attention globally:

> *'Tesla's plans to use its new battery storage system to power homes will provide households with more opportunities to reduce bills.*
>
> *But it will also cause headaches for the electricity distribution companies.*
>
> *The companys founder, Elon Musk, announced last week that it had developed the Powerwall batteries that could store electricity generated from solar panels.*
>
> *The idea is to store the energy generated during the day, when demand is relatively low, that can then be used to power a home during the evening when the demand is higher. It can also act as a backup supply during any power cuts.*
>
> *The Powerwall battery packs come in 7kWh or 10kWh units and cost US$3,000 or US$3,500 respectively. Up to nine units can be stacked together to give a maximum 90kWh.*
>
> *Musk made the announcement at a press conference that was powered entirely by batteries.*
>
> *Musk told the audience that it was possible to place orders now for the units with delivery expected in the next three months.'*[364]

The AER is only very slowly accepting that disruptive technologies have resulted in increased risk in the recent term:

> *'ActewAGL submitted that UBS has been conducting research into solar PV, battery storage and electric vehicles for over two years. We recognise our empirical equity beta estimates are measured over a relatively long estimation period. However, we also consider estimates measured over the last five years. This is consistent with ActewAGL's submission that disruptive technologies have increased risk for Australian energy distribution businesses over the last five years.*
>
> *Further, we recognise the development of disruptive technologies in the Australian energy sector may create some non-systematic risk to the cash flows of energy network businesses. We consider these can be more appropriately compensated through regulatory cashflows (such as accelerated depreciation of assets).'*[365]

The above treatment of the issue is demonstrably inadequate on its own terms. The above passage notes that the shortest time frame for the AER's beta estimates is five years, while acknowledging that this effect has only really begun to be recognised in the last two years. Although the AER acknowledges that its five year estimates show increased risk (and obviously if the effect has only begun in a significant way over the last two years it will show up in a diluted way in this five year estimate), the AER continues to give weight to beta estimates measured over a relatively long period of time. Additionally, the AER's comparator firms are mainly gas businesses that are not directly affected by the risks of disruptive technologies that we have explained.

---

[363] See Business Spectator; *In awe of Elon Musk's wonderwall – a utility killer*; 4 May 2015; http://www.businessspectator.com.au/article/2015/5/4/energy-markets/awe-elon-musks-wonderwall-%E2%80%93-utility-killer

[364] See InDaily; *Winners and losers in solar battery plan*; 5 May 2015; http://indaily.com.au/opinion/2015/05/05/winners-and-losers-in-solar-battery-plan/

[365] AER; *Final Decision, ActewAGL distribution determination 2015-16 to 2018-19*; Attachment 3 - Rate of Return; April 2015 at [3-381].

Despite acknowledging this increased risk, the AER's Preliminary Determination imposes a lower equity beta than ever before.

The AER has again sought to suggest that this risk is more appropriately managed through regulatory cashflows. We previously explained that would be untenable if a significant number of customers elected to disconnect. The AER seems to accept that point but effectively responds to the effect that if we were properly compensated for the risk then it may lead to increased costs for consumers which might in turn exacerbate the disconnection effect we raised:

> *'SAPN questions the benefit of utilising such cash flow measures to reduce risk because these measures assume network service providers have a large customer base to absorb the increased costs. It considers the measures would not be appropriate in a situation in where an 'endless spiral' of disconnections commences. However, increasing the allowed rate of return (through equity beta) also increases the costs to consumers, and as such we consider the same assumption applies.'*[366]

In other words, the AER's Preliminary Determination proposes to exacerbate risk by introducing the proposition that the risk should not be passed through to the customer base and instead it should be borne by network businesses and their equity investors. This is contrary to the allowed rate of return objective that requires (for good reason) that our allowed rate of return for equity should be commensurate with that of a benchmark efficient entity with the same degree of risk as SA Power Networks.

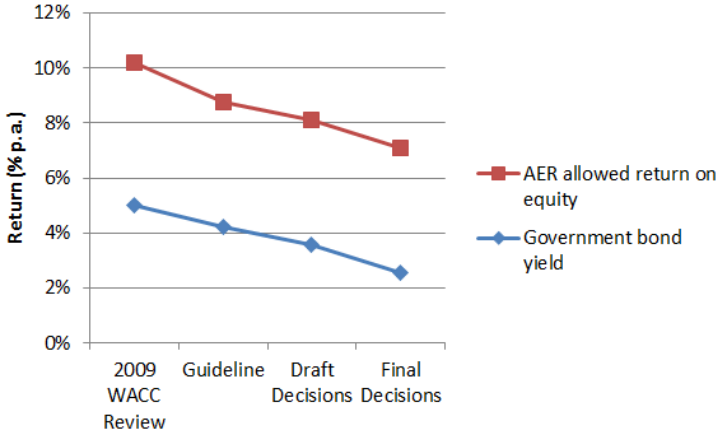
(c) The multi-model approach vs the foundation model approach

The new Rules for the setting of equity returns were intended to broaden the inputs that the AER used when setting the return on equity and enable an allowance to be set that better reflected prevailing market rates rather than the quirks of a particular financial model.

However, the AER has effectively made no substantive change to its approach by continuing to exclusively use the SL-CAPM, calling it a 'foundation model', to dictate the range of equity returns it is willing to countenance. Even within the constraints of this model, the use of any other relevant evidence is compared with the AER's 'primary' evidence and if the other relevant evidence deviates too much from the SL-CAPM it is wholly disregarded. As Gray and Hall's report illustrates, despite evidence from the Reserve Bank that rates in equity markets have not fallen, the AER's adherence to an unrealistic static implementation of the SL-CAPM foundation model is delivering erroneous downward estimates of the required return on equity:

[366] AER Preliminary Determination Attachment 3 at [3-376] to [3-377].

Figure 1: Government bond yields and the AER's allowed return on equity



Source: AER decisions.

Gray and Hall summarise as follows:

> *'The AER's approach of setting the allowed return on equity by adding a fixed premium to the government bond yield is the same as its approach under the previous Rules. This approach produces the same outcomes as under the previous Rules – the allowed return on equity is a lucky dip for regulated firms that depends entirely on the level of government bond yields over 20 days at the beginning of their regulatory period.'*[367]

Gray and Hall's companion report, provides equity allowances that would have applied using the AER's approach at different points. The stark conclusions are that the cost of equity is both lower than alternative measures and volatile moving in lock step with movements in the prevailing yields on Commonwealth Government Securities.[368]

The foundation model imposes restrictive constraints that effectively deprive other evidence from affecting the allowed rate of return. First, the functional form of the SL-CAPM restricts how this other information is being used. Second, the AER's approach of ranking the information as primary or secondary information and then effectively giving the primary information a dominant role ensures that the result hardly deviates from the AER's mechanistic implementation of the SL-CAPM. Gray and Hall state:

> *'The AER's consideration of parameter inputs for beta and the market risk premium results from the application of binding constraints, despite the AER's statements to the contrary. Throughout the AER's Guideline process, and since, we have objected to the AER's use of a 'primary' subset of the relevant evidence to produce apparently immutable ranges for parameter estimates, with all other relevant evidence relegated to the role of (at most) informing the selection of a point estimate from within the primary range.'*[369]

In support of the SL-CAPM's use as the foundation model for determining the allowed rate of return for equity, the AER has stated that:

---

[367] Frontier; *Key issues in estimating the return on equity for the benchmark efficient entity*; June 2015; paragraph 114; page 37.
[368] Frontier, *Cost of equity estimates over time*, Figure 6, page 24.
[369] Ibid; paragraph [118]; page 39.

'We consider there is overwhelming evidence that the SL-CAPM is the current standard bearer for estimating expected equity returns.'[370]

In real armies, standard bearers are merely one of many soldiers comprising a company who go into battle together. Similarly, we support using the combined strength of multiple models – including the AER's preferred 'standard bearer' SL-CAPM, despite the fact that it has been shown to deliver less accurate results than the other models. Where all the measures are imperfect, the benefits of diversity are strong and what we propose in relation to determining the allowed rate of return for equity is similar to the AER's own approach of taking a 50:50 average of the Bloomberg and RBA quotations for debt benchmarks and is supported by the reasons the AER itself advances when taking an average of the two third party debt providers.

In the US, regulators have long had the discretion to use a range of models and the views of experts from that jurisdiction are therefore persuasive. As Malko[371] explains:

'Which models are useful for economic regulatory purposes?

In my opinion, all of the models discussed above are useful in the determination of allowed return on equity, but each model has both strengths and drawbacks and should not be used alone, nor is any model superior so as to warrant its use as a primary or sole principal model.

In particular, the models can be grouped into two 'families': the DGM on the one hand and all the capital asset pricing models or interest rate sensitive models on the other based on how they explain and predict returns. Both major groupings, and all the variants discussed above, provide useful insights into what returns that risks-adverse investors expect to receive when making investments.[372]

Multiple Model Approaches are Preferable

In my opinion, no one single financial model is sufficient to estimate the rate of return in every economic circumstance. All models suffer a range of theoretical and/or empirical weaknesses of different kinds. If only one model is used, or if one model is given excessive pre-eminent weight, investors' returns will be highly dependent on the extent to which that model's particular weaknesses lead to over- or under-returns. If multiple models are used, then the returns will vary in response to all the weaknesses but to a smaller extent than if one model is used. It also stands to reason that where the weaknesses of different approaches are directionally different, they will to some degree cancel each other out. Additionally, where only one model is used there is insufficient corroborating evidence or ability to cross-check the results. By contrast, the consideration of multiple models enables the decision maker to either become comfortable that different methodologies are corroborative or, where they are not, to question why it is that one or more models may be delivering significant different results at a particular time or in particular economic circumstances. This, in turn, can give an insight into whether results should be adjusted or altering the weighting or influence accorded to particular models and their results.

In my opinion, to ensure the most appropriate decision, it is important to consider the results of several models. In my opinion, using several models helps

[370] AER, *Preliminary Determination* Attachment 3 at [3-122].
[371] Malko; paragraphs [8.1-8.2]; pages 9-10.
[372] Ibid; paragraphs [8.1-8.2]; pages 9-10.

compensate for the drawbacks in any single model and increases the probability that the appropriate and reasonable range is identified.[373]

I have observed that in the United States regulators and expert financial witnesses generally use multiple methods, at least two, when determining a reasonable range and reasonable point estimate for the cost of common equity for a regulated energy utility.'[374]

Knecht agrees that capital asset pricing models should be used together with the DGM:

> *'Long-term market trends will tend to drive the estimates of one model higher than another for some years and then lower for another stretch of time. This fact justifies both the use of a wide range of models and also the continuation of the same set of models through these variations.*
>
> *Using a number of different models is superior to relying on a more limited selection of models. This is because the CAPM, ECAPM, FF3F, and CA+I estimates use basic cost of capital data in a different manner to the DCF models. The CAPM, ECAPM, FF3F and CA+I models extract information from the Cost of Capital data that the DCF models miss – and vice versa. Using multiple models provides additional perspectives and information, yielding a more accurate, reliable, and robust estimate.'*[375]

The AER should adopt the multi-model approach for the same reasons. Locally, Gray and Hall hold a similar view:

> *'[W]hat the Rules require is an identification of all estimation methods, financial models and other evidence that may be relevant to estimating the return on equity. Following that identification, and assuming that there is more than one information source that is relevant, some weight will need to be ascribed to the information sources or they will somehow need to be combined to produce a point estimate. The Rules do not specify that the Sharpe-Lintner CAPM is to be used unless a model about which there is no debate or potential weaknesses is identified. Each of the information sources, including the Sharpe-Lintner CAPM must be fairly assessed if the estimate of the return on equity is to be arrived at on a reasonable basis and be the best forecast or estimate possible in the circumstances. The evidence supports a finding that the best forecast or estimate is one that is properly informed by estimates from a range of evidence, including the Sharpe-Lintner CAPM, the Black CAPM and the Fama-French model.'*[376]

Further, as explained below, some models are better able to address certain market circumstances and in particular, CEG notes that in the highly unusual prevailing circumstances of negative betas for CGS, the DGM model is better able to cope.

In summary, not only is the 'foundation model' concept significantly sub-optimal, choosing the SL-CAPM as the foundation model is a serious flaw in the AER's Preliminary Determination. At the very least there should be two models, one drawn from each predominant 'family' of models. Further, the capital asset pricing contribution must either include models that are free of the low beta and book-to-

[373] Ibid; paragraphs [9.1]-[9.2]; page 10.
[374] Ibid; paragraph [9.5]; page 10.
[375] Knecht, RL; Statement; 19 June 2015 (**Knecht**); paragraphs [4.4-4.5]; page 3.
[376] SFG Consulting; *The foundation model approach of the Australian Energy Regulator to re-estimating the cost of equity*, Report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Ergon Energy, Powercor, SA Power Networks, and United Energy; 27 March 2015; paragraph [107]; page 22.

market biases or corrections need to be made to off-set those biases. It is wrong to suggest that giving the DGM, or DCF model, a 25% weighting in establishing the return on equity allowance would constitute a dangerous regulatory experiment. To the contrary, wherever the debate concerning capital asset pricing models ends, the DGM or DCF definitely should be employed (ideally concurrently) when establishing an allowed rate of return for equity. A decision not to give one entire family of models any weight would be to forego the only available 'counter-weight' to the limitations that apply to capital asset pricing models as a group.

In each of the subsequent sections, we make additional submissions in relation to each of the models that should be used in a multi-model approach that is well implemented.

(d) The DGM or DCF model

Handley's most recent report states the following in relation to the DGM or DCF:

> *'the regulatory environment involving an aggregate regulatory asset base measured in the tens of billions of dollars is not an appropriate setting to trial a new model whose widespread use and acceptance is yet to be established.'*[377]

This statement effectively advances the highly conservative proposition that a national energy regulator should never move away from the sum total of its own specific experience or it is an assertion that is ignorant of international practice. If we accepted that approach, improvements in the approach could never be adopted and this would be contrary to the Rules requiring that regard be had to all the relevant information in seeking to set an allowance that is commensurate with the efficient costs that a benchmark business would face.

In any event, Handley's statement is wrong. A discussion of economic models used for economic regulation of energy network businesses would logically begin before the SL-CAPM began to be used at a time when only the US was engaged in the use of economic models to establish permitted returns for profit making energy networks. The first model to be used for this purpose was the DGM or DCF in the US where it continues to be regarded as the most tried and true of methods for establishing a market based return on equity. As Malko explains:

> *'The Dividend Growth Model (DGM), also the DCF, is based upon the works of Irving Fisher and John Williams in the 1930s. The DGM or DCF was introduced for estimating the cost of common equity for regulated energy utilities by state regulatory authorities during the 1960s and early 1970s. Professor Myron J. Gordon is frequently recognized to be the "pioneer" or "father" of the DCF model for application in estimating the cost of common equity for a regulated energy utility. See the following: Myron J Gordon; The Cost of Capital to a Public Utility; Michigan State University Public Utilities Studies, East Lansing, Michigan, 1974.*
>
> *....*
>
> *The adoption of the DGM or DCF constituted a significant advance in the science of what constitutes a fair market reflective rate of return.* ***This model is still considered and almost universally used, alone or in a multi-model approach (as I discuss further below), by almost all energy regulators in the United States****.'*[378]

[377] Handley J; *Advice on the Rate of Return for the 2015 AER Energy Network Determination* for Jemena Gas Networks, Report prepared for the Australian Energy Regulator; 20 May 2015.
[378] Malko; paragraphs [3.1] to [3.2]; page 4.

In dismissing the DGM or DCF for use in directly estimating the cost of equity for benchmark businesses in this country, the AER has stated that:

> *'We also considered that the sensitivity of DGMs to input assumptions would limit our ability to use a DGM as the foundation model. For example estimates of simple DGMs (such as those previously proposed by CEG) have provided implausible estimates of the returns on equity for the benchmark efficient entity. For example, in the Guideline we found that simple DGMs generate average returns on equity for energy infrastructure businesses over an extended period that significantly exceeded the average return on equity for the market. This did not make sense as the systematic risk of network businesses is less than the overall market.'*[379]

However, Malko advises that these potential difficulties are much exaggerated. Having reviewed the above statement by the AER he responds as follows:

> *'In response, I would make the following observations:*
>
> *Certainly the DGM is sensitive to its input assumptions and if it would be inappropriately implemented, it could deliver implausible results. In this regard, I see no difference between this and other models. If inappropriate inputs are used, any of the models can produce implausible results.*
>
> *It is common in United States regulatory determination processes for there to be debate between businesses, customers and the regulators concerning which inputs to use but these debates occur with a context in which expert testimony has regard to whether the inputs used deliver plausible results and decision making is guided by a body of court and regulatory precedent.*
>
> *Over-all, the wide acceptance and use of the DGM in the United States demonstrates that this model is sufficiently robust for it to be useful in economic regulatory decision making.'*[380]

The AER also asserts that there may be issues that are specific to Australia as to why the DGM or DCF is inappropriate and in that regard it is appropriate to consider the views of Australian experts. In its previous papers rejecting the use of the DGM or DCF the AER asserted that a Grant Samuel report, which valued Envestra, provided support for several key features of the AER's approach. However, Grant Samuel has reacted with a vigorous rebuttal of the AER's use of its work and a more general explanation of its disagreement with almost every aspect of the AER's equity analysis. In particular, before turning specifically to the merits of using the DGM or DCF, Grant Samuel explains why it is important in their work to look beyond the SL-CAPM:

> *'In this case, it seems that the AER's approach has been to avoid changing its existing (single) formula "foundation model" and proceed on the basis that as long as it can show that the model is widely used and the individual inputs can be justified, there is no need to concern itself with whether or not the final output is commercially realistic.'*[381]

---

[379] AER, *Preliminary Determination*, Attachment 3 at [3-257].
[380] Malko; paragraph [3.7]; page 5.
[381] Letter from Grant Samuel & Associates Pty Limited (Grant Samuel) to the Directors of Transgrid; 12th January 2015 (**Grant Samuel Letter**); page 2.

Grant Samuel expresses a considerable degree of frustration that the AER applies 'double standards' when rejecting the use of the DGM to directly estimate the cost of equity and concurrently resolving to adhere primarily to the SL-CAPM. Grant Samuel states:

> *'The DGM, in its simplest form, has only two components to estimate – current dividend yield and the long term growth rate for dividends. The current yield is a parameter that can be estimated with a reasonably high level of accuracy, particularly in industries such as infrastructure and utilities. We accept that the question of the long term dividend growth rate becomes the central issue and is subject to a much higher level of uncertainty (including potential bias from sources such as analysts) and we do not dispute the comments by Handley on page 3-61.*
>
> *However, there is no way in which the issues, uncertainties and sensitivity of outcome are any greater for the DGM than they are with the CAPM which involves two variables subject to significant measurement issues (beta and MRP). The uncertainties attached to MRP estimates in particular are widely known yet are glossed over in the AER's analysis of the relative merits. Section D of Attachment 3 of the Draft Decision contains almost 40 pages discussing the most esoteric aspects of methodologies for calculating beta but in the end the AER's choice of 0.7 is, in reality, an arbitrary selection rather than a direct outcome of the evidence.*
>
> *Moreover:*
>
> - *the plausible beta range nominated by the AER (0.4-0.7) creates a 2 percentage point swing factor for the CAPM-based cost of equity. Its own expert nominated an even wider range (0.3-0.8);*
> - *the 40 pages contain little meaningful discussion of issues such as standard errors or stability over time (as opposed to different time periods). Data on these aspects would be important to properly evaluate the overall reliability of the statistics; and*
> - *the publication of only averages for individual companies and not the range hides the underlying level of variability in these measures.*
>
> *In short, the claim of superiority for the CAPM is unfounded.'*[382]

Grant Samuel adds:

> *'It is also difficult to fathom why the AER states that the DGM is highly sensitive to interest rates but makes no mention of the sensitivity of CAPM to interest rates.'*[383]

And Grant Samuel points out:

> *'The AER also seeks to distinguish discount rates for valuations from discount rates for regulatory purposes by the fact that valuations have a perpetuity timeframe (and must reflect expectations of investors over that timeframe) while the regulator sets the return on equity only for the length of that regulatory period (typically five years). We do not believe this distinction is valid. For a start, the AER adopts a 10 year term for its overall rate of return (page 3-25) including a 10 year risk free year rate so if the five year timeframe of the Draft Decision was*

[382] Ibid; page 3.
[383] Ibid; page 2.

paramount then its own methodology is inconsistent with the return objective. In any event, it is our view that the relevant period is always a perpetuity, even in the context of a five year regulatory period. The rate of return over the five year period can only be realised if the capital value is sustained at the end of the period. The sustainability of the capital value at the end of year five is in turn dependent on cash flows beyond year five (ie the cash flows in perpetuity).'[384]

Grant Samuel notes:

'In our opinion, in examining the CAPM and comparing it to the DGM, the AER has unfairly accentuated the failings of the DGM while, at the same time, it has ignored many real shortcomings in the CAPM.'[385]

Grant Samuel also disputes the notion that the DGM is not used in practice.

Gray and Hall state:

'The AER applies different standards to its assessment of the SL CAPM relative to other models. By way of some examples:

i. The AER rejects other models on the basis that the outputs are potentially sensitive to different estimation methods, when the same is true of the SL CAPM. In its recent final decisions, the AER's own range for the allowed return on equity from the Sharpe-Lintner CAPM is 4.6% to 8.6%.

ii. The AER cites certain empirical studies to support its rejection of other models. However, the only reasonable interpretation is that the body of available evidence supports the empirical performance of other models over the Sharpe-Lintner CAPM. In some case, papers that the AER cites as supporting the Sharpe-Lintner CAPM actually do the opposite.

iii. The AER rejects all estimates for other models on the basis that it finds some of them to be implausible.'[386]

Lane and Rosewall of the RBA state:

'DCF analysis is a standard method recommended by finance theory to evaluate investment opportunities.[387]

…

Because it provides a natural threshold to accept or reject investment decisions, the discount rate used in DCF analysis is often called the 'hurdle rate'.[388]

…

A typical firm in the Bank's liaison program evaluates discretionary capital expenditure by using DCF analysis, and also by considering the payback period as a supporting consideration. This is in line with the evidence from other advanced economies such as the United States and the United Kingdom (see below) and is also in line with earlier survey evidence for Australia.[389]

---

[384] Ibid; page 5.
[385] Ibid; page 2.
[386] Frontier; *Key issues in estimating the return on equity for the benchmark efficient entity*; June 2015; paragraph [17]; page 7.
[387] Kevin Lane and Tom Rosewall; '*Firms' Investment Decisions and Interest Rates'* (2015) June Quarter Bulletin; page 2.
[388] Ibid.
[389] Ibid; page 3.

…

The available evidence suggests that firms in other advanced economies undertake investment decisions using similar criteria employed by Australian firms. Surveys have found that firms in the United States and Europe tend to evaluate proposed investments using discounted cash flow techniques, which have become more popular over the past few decades, and the payback period.'[390]

Further, as discussed below in the section concerning the merits of a multi-model approach, CEG has explained how the DGM is better able to address the highly unusual prevailing condition in which the CGS is observed to have a negative beta[391] and is unsafe to use as an proxy for the SL-CAPM risk free rate – unless it is adjusted.

In summary, the DGM or DCF could be regarded as the safest, most tried and true model of all.

(e) The SL-CAPM

We do not object to the use of the SL-CAPM blended with the estimation of other relevant (and arguably superior) models when establishing an allowed rate of return for equity. However, we do object to the AER's Preliminary Determination approach of:

- elevating the SL-CAPM to being the 'foundation model' that materially constrains the contribution other models can make; and
- implementing the SL-CAPM in the idiosyncratic way that the AER does with particular reliance on historical long-run average estimates of the MRP, which can only reflect the long-run average market conditions over the period of estimation, and combining that with a very short averaging period for the risk free rate. The AER also takes an unprecedented approach to parameter selection (for example in relation to beta as discussed below) that is inherently unable to deliver an adequate allowed rate of return.

Further, we consider that regard needs to be had to the problems that CEG has identified in the current, highly unusual prevailing market circumstances in which CGS yields are observed to have a significant negative beta.

In relation to the first issue, NERA states:

'The model tends to underestimate the mean returns to low-beta assets, value stocks and, in the US and some other countries, low-cap stocks. A value stock is a stock that has a high book value relative to its market value or, identically, a low market value relative to its book value. A growth stock is a stock that has a low book value relative to its market value or, identically, a high market value relative to its book value.'[392]

Handley's latest report that purports to support the AER's foundation model approach requires careful consideration. He avoids giving any support to the SL-CAPM as an accurate way of establishing a

[390] Ibid; page 5.

[391] The negative beta for nominal CGS arises because the bond holder will receive a high payout during periods of low inflation – see footnote 14 of CEG; Measuring expected inflation for the PTRM; June 2015.

[392] NERA; *Review of the Literature in Support of the Sharpe-Lintner CAPM, the Black CAPM and the Fama-French Three-Factor Model*, A report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Ergon Energy, Powercor, SA Power Networks, and United Energy; March 2015; page 22.

commensurate market return and accepts that the SL-CAPM is subject to 'well-known' low beta and book-to-market biases, and that evidence of these biases is 'nothing new.'

The central theme of the report is to undermine the use of other capital pricing models based on the assertion that the literature does not conclusively prove that the superior conceptual and empirical performance of those models is due solely to an analysis of systematic risk. Handley effectively asserts that the only relevant factor in the rate of return objective concerns systematic risk.

Reading Handley's report, a reader who was not familiar with the rate of return objective might reasonably expect the objective to direct the AER to consider only systematic risk and nothing else but the Rules do not limit the AER in this way.

The focus of the rate of return objective is to set a regulatory rate that is commensurate with the efficient financing practices of a benchmark firm. It is unsurprisingly that the objective notes that the assessment needs to be for a firm 'with a similar degree of risk'[393] but the task is to establish a commensurate return. There is nothing to suggest that models that provide valuable insights on how to establish an accurate commensurate return should be dismissed regardless of whether or not the model is limited to an assessment of risks.

It would be completely perverse if any factor that significantly affected the required rates of return for investors was ignored. The result would be that efficient investments would not occur (if excluding the relevant factor led to a below market return) or prices would be inflated (if the excluding the relevant factor led to an above market return).

Nevertheless, of all the possible reasons that Handley lists to explain why real world observed returns might differ from the SL-CAPM the most plausible is that it is a measure of risk.

Handley's approach is clearly not practical in the real world or in regulatory processes. By contrast, Grant Samuel explains that real world valuations need to be informed by a range of additional material to overcome the significant limitations of solely relying on a plain or 'SL- CAPM':

> *'[O]ur approach … is to form an overall judgment as to a reasonable discount rate rather than mechanistically applying a formula. The fact is that, particularly in some market circumstances, the CAPM produces a result that is not commercially realistic. When this occurs it is necessary and appropriate to step away from the methodology and use alternative sources of information to provide insight as to what is, after all, an unobservable number that can only be inferred. In our view, Envestra was clearly a case in point.*
>
> *In using the Envestra report, the AER seems to be to trying to co-opt the parameters that we used for calculating the initial CAPM based rate to bolster its own case while trying to find ways to justify not having to recognise the fact that for the valuation of Envestra Limited's assets, we actually selected a different rate (ie 6.5-7.0% or, more correctly 6.5-8.0%, rather than 5.9-6.5%).'*[394]

The allowed rate of return used in Australia effectively codifies long standing US case law:

> *'[T]he return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks.'*[395]

[393] The Rules; Rule 6.5.2(c); page 662.
[394] Grant Samuel Letter; pages 4-5.
[395] *Federal Power Commission v Hope Gas Co 320 US 591* (1944) at 603.

In doing so, the same US case law also includes the requirement in the Australian Revenue and Pricing Principles concerning the necessity for the business to have a reasonable opportunity to recover its efficient costs:

> *'That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.'*[396]

The above case was decided in 1944 and in the US there is a history of applying the standards articulated above. In the past, sole reliance was placed on the DGM or DCF model but it has never been the case that a mainstream US approach was to solely rely on the SL-CAPM. Malko explains how the SL-CAPM began to be introduced in the US:

> *'In particular, when base interest rates were high, there was a concern (legitimate in my view) that the DGM or DCF did not, at the time, adequately reflect the increased returns that equity investors expected to receive and this led some regulators to start to have regard to the capital asset pricing models concurrently with the DGM or DCF.'*[397]

Of the SL-CAPM, he notes:

> *'In my opinion:*
>
> *The Sharpe CAPM has important strengths, including:*
>
> - *It incorporates a first principles concept of risk and return.*
> - *It is an interest-rate sensitive model that complements a stock price sensitive model.*
> - *It is simple.*
>
> *The Sharpe CAPM model has important limitations, including:*
>
> - *It is a single factor (beta (β)) model and it does not incorporate other factors that finance literature demonstrates are known to affect equity returns.*
> - *The model suffers from a theoretical limitation in that it assumes that investors can borrow and lend at the risk free rate which is not the case. Due to the simple mathematical specification of the model, the effect of this implausible assumption is that it under-estimates the returns for investments of below average risk and over-estimates the returns for investments of above average risk.*
> - *Empirical work shows that there are limitations associated with its ability to explain past stock price movements and equally its predictive capabilities both associated with the theoretical limitations mentioned above and more generally.'*[398]

Reflecting these weaknesses, Malko notes that even when the SL-CAPM is used in conjunction with the traditional DGM method, the contemporary approach is to make adjustments to account for the significant limitations of the SL-CAPM:

[396] Ibid.
[397] Malko; paragraph [3.8]; page 6.
[398] Ibid; paragraphs [4.3] to [4.4]; pages 5-6.

'I have observed that during the recent past (10 years or less), financial analysts have attempted to address some of the shortcomings of the Sharpe CAPM by:

- *Using the Empirical CAPM (**ECPAM**) (discussed below).*
- *Making an adjustment by adding the small size risk premium. This premium reflects that small companies have higher returns on average than larger companies (which is also relevant to the discussion of the FFM below).*
- *Applying the Hamada adjustment for a leveraged beta. This adjustment reflects a changing capital structure. For example, if a utility's current or planned capital structure reflects an increased debt level and debt percentage, then the leveraged beta is increased to reflect the increased financial risk. To make the Hamada adjustment, a comparison of the capital structure of a specific utility to a comparable group is undertaken and appropriate mathematical models are applied.'*[399]

A further important consideration is how to implement the SL-CAPM and in particular whether to use the Ibbotson approach, the Wright approach or a combination of the two. Each of these approaches takes an extreme position on a continuum of how movements in the market risk premium may be related to movements in the base interest rate. The Ibbotson approach (takes the position that the market risk premium remains wholly unchanged as interest rates vary while the Wright approach takes the position that movements in the MRP are exactly offset by equal movements in the risk free rate.

In fact both of these extreme positions are unrealistic. In fact, equity returns are observed to vary when the base rate varies but the movements in equity returns are smaller than the movements in base rates. In other words the MRP is observed to counteract or 'cushion' movements in the base rate.

A flaw of the AER's foundation model is that, like the Ibbotson approach, it takes the extreme position that MRP is an unmoving constant in the face of changes in the base rate. By contrast, SA Power Networks' equally weights the contribution of the two extremes on the continuum and in this regard the proposal is both moderate and better reflective of the way markets actually behave.

Further, as CEG has explained, there is a significant problem with using an un-adjusted CGS return as the proxy for a risk free rate in the current highly unusual prevailing market conditions.

Dr Hird states:

'The first critical point to note is that the fall in CGS yields cannot be mechanically assumed to have been associated with a fall in the cost of equity. Instead, the cost of equity must be estimated directly and not assumed to fall/rise with CGS yields.

The pattern of beta for CGS and other government bonds internationally gives rise to two critical implications for the use of CGS yields as the proxy for the risk free rate in CAPM. That is, two adjustments to regulatory practice are required to account for the pattern of observed betas on CGS through time:

- *The prevailing risk free rate must be adjusted upwards from the prevailing nominal CGS yield by around 1.0% to account for the fact that*

[399] Ibid; paragraph [4.5]; page 6.

> *the best estimate of the prevailing nominal CGS beta is materially negative;*
>
> - *The historical average excess returns needs to be adjusted upwards by around 0.7% to account for the fact that historical average betas for CGS (against which excess returns have been measured) were above zero.'*[400]

However, this issue can be addressed with an adjustment:

> *'Consequently, if the best estimate of the historical average MRP relative to CGS is 6.0% (AER) or 6.5% (NERA) then the best estimate of the MRP relative to the true (unobservable) zero beta asset is 6.7% to 7.2%. If the historical average asset beta on nominal 10 year CGS is higher than 0.1, then these estimates will in turn be larger as well.'*[401]

Also, this is a further reason to use the multi-model approach. The DGM is better able to cope with this issue and using that model concurrently with the SL-CAPM in a multi-model approach would significantly ameliorate the situation:

> *'If the cost of equity is being estimated using a prevailing estimate derived from the dividend growth model (DGM) then a much smaller, or even a zero, adjustment is required to the CGS yield. This is because the DGM will automatically 'pick up' any downward bias in CGS yields in the form of a higher estimated MRP relative to CGS yields.'*[402]

In summary, while the SL-CAPM can be used:

- it must be supplemented with estimates from each other relevant model; and
- there needs to be a midpoint approach to implementation between the Ibbotson and Wright approaches to estimating the MRP to avoid significant unwarranted cyclical under (over) estimates in times of unusually low (or high) base interest rates.

(f) Parameter selection within the SL-CAPM

As we have explained above, Frontier Economics has explained that the AER has mis-understood how to go about assigning a beta to an electricity network business with a 60:40 debt to equity capital structure facing an onslaught of disruptive technologies.

The AER does not follow the range of 0.3 to 0.8 that its own advisor Henry has provided. Instead it uses its own more constrained range of 0.4 to 0.7. Despite acknowledging that other inputs deliver a broader range (eg, empirical estimates of international energy networks which range from 0.3 to 1.0 or 1.3) the AER is unmoving in its adherence to the tightly limited, low beta range.

Then, the process of selecting from within the range is a confused one. For example, one of the key considerations that the AER uses in selecting a value at the upper end of the range is the 'theoretical principles underpinning the Black-CAPM'.[403] On the basis of evidence provided by Gray and Hall, we are strongly of the view that the beta needs to be not only at the high end of the AER's range but

---

[400] CEG: *Measuring risk free rates and expected inflation*; April 2015; paragraphs [75-76]; page 24.
[401] Ibid; paragraph [81]; page 25.
[402] Ibid; paragraph [82]; page 25.
[403] AER, *Preliminary Determination* Attachment 3 at [3-417] to [3-420].

higher still. However, the idea that the 'theoretical principles' of the Black-CAPM supports a beta uplift betrays a misunderstanding of those principles.

The point of the Black-CAPM is not that the SL-CAPM estimates a beta that is too low; rather these principles indicate that the intercept (ie return on the risk free asset) should be higher than the SL-CAPM predicts and the slope of the risk-return curve are likely to differ from that specified in the SL-CAPM. In other words, for any given beta, the returns should be higher – the principles do not support the notion that the beta itself should be adjusted.

Gray and Hall summarise this issue as follows:

> *'In relation to the Black CAPM, the AER performs no calculations, but states that it has used the theoretical principles underpinning the Black model to inform its estimate of equity beta for the Sharpe-Lintner model. The AER does not explain (a) how one goes about using the theoretical underpinnings of one model to adjust a parameter estimate for another model or (b) the magnitude of the adjustment (if any) that was made.'*[404]

The AER's use of the theoretical underpinnings of the Black CAPM to adjust the equity beta in the SL-CAPM is unique to the AER and has the disadvantages that (a) the outcome is an estimate that is not true to either model, and (b) it is impossible to determine whether the size of the adjustment was appropriate.

Equally erroneous is the AER's approach to selecting the MRP to be used in the SL-CAPM. The key flaws are that:

- geometric averages are inappropriate to use because the AER's equity model is a non-compounding model, and even if it was appropriate to use them, there is no basis for the AER's approach of adding 20 basis points to its geometric estimate and defining the result to be the bottom of the reasonable range for MRP in all possible market conditions;
- the long run estimate that the AER insists on using is based on data that has been arbitrarily adjusted downwards to account for missing data from almost a hundred years ago. This is done on the basis of a very narrow 'back of the envelope' calculation which has been inaccurately attributed to the Australian Stock Exchange rather than using a study that covers many times as many observations to develop a more considered adjustment factor;[405]
- despite evidence to the contrary,[406] the AER continues to rely on the Brailsford, Handley and Maheswaran historic returns data set which relies on dividend yields services calculated by Lamberton later adjusted.[407] NERA has recreated Lamberton's series and 'overall the match between our results and those that Lamberton provides is good. Using the data in Table 2.3, the correlation between our estimate of the equally weighted average yield to dividend paying issues (firms) and his estimate is 1.00 (0.98) (rounded to two decimal places);'[408]
- the AER does not take full heed of a broad range of other inputs (such as the DGM analysis) that show the MRP must be higher than the high point of the range that is produced by historical mean excess returns. Indeed the AER's updated DGM estimate in the Preliminary Determination increases the upper bound of the MRP range materially but there is no change to the point estimate; and

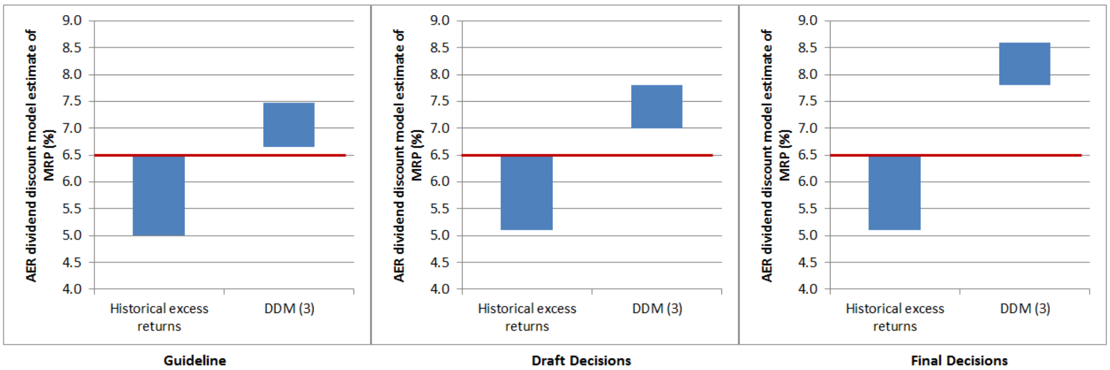
---

[404] Frontier; *Key issues in estimating the return on equity for the benchmark efficient entity*; June 2015; paragraph [159]; page 48.
[405] NERA; *Historical Estimates of the market risk premium*; February 2015.
[406] Ibid.
[407] Handley, JC; *Further Advice on the Return of Equity*, Report prepared for the Australian Energy Regulator; 16 April 2015; page 7.
[408] NERA; *Further Assessment of the Historical MRP: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors*, A report for United Energy; June 2015; page 10.

- there is no basis for the AER's approach of limiting the MRP to a maximum of 6.5% in the prevailing market conditions, when for conceptual reasons and having regard to market data, it is known that the prevailing MRP is higher than the long run average.[409]

Gray and Hall's charts illustrate the third of these points well:

Figure 2: AER estimates of MRP from historical excess returns and the dividend discount model



Source: AER Rate of Return Guideline, AER draft decisions, AER final decisions

(g) Addressing the downward bias for low beta stocks in the SL-CAPM

As explained in the previous section, the AER's selection of beta is inappropriate. Further, having selected a beta the AER fails to take the necessary steps to address the downward bias in returns that the model delivers for betas of below 1.

As noted above, Handley's latest report for the AER effectively asserts that if there is any doubt that a model's explanatory power is not focused wholly on risk, he would disregard it entirely and he does exactly this in relation to the Black-CAPM and Fama French Three Factor Model:

> *'[E]mpirical evidence of a low beta bias is not sufficient on its own to justify a claim for additional compensation relative to the Sharpe-CAPM.*
>
> *The key point is that there are multiple possible (but not necessarily mutually exclusive) explanations for the low beta bias. In other words, we do not have a clear understanding of what the low beta bias represents. This uncertainty is critically important in the current context because it means that the low beta bias does not necessarily reflect risk, whereas the allowed rate of return objective is clear that risk is the key determinant of the rate of return.'*[410]

For the reasons set out above, that approach is far too limited. The allowed rate of return seeks a return that is commensurate with the efficient costs of a benchmark firm and if other capital asset pricing models improve upon the SL-CAPM, they should be employed.

CEG, Gray and Hall,[411] and NERA, have consistently explained that the SL-CAPM has a low beta bias.[412] This is not surprising because the model relies on a wholly unrealistic assumption that investors can borrow and lend at the risk free rate. NERA states that:

---

[409] Ibid; paragraph [128]; page 41.

[410] Handley, JC; *Advice on the Rate of Return for the 2015 AER Energy Network Determination for Jemena Gas Networks, a report prepared for the Australian Energy Regulator;* 20 May 2015; page 5.

[411] For example see Frontier; *Key issues in estimating the return on equity for the benchmark efficient entity*, a report prepared for ACTEWAGL Distribution, AGN, AusNet Services, CitiPower, Ergon, Energex, Jemena Electricity Networks, Powercor, SA Power

'The data indicate that there is a negative rather than a positive relation between returns and estimates of beta. As a result, the evidence indicates that the SL CAPM significantly underestimates the returns generated by low-beta portfolios and overestimates the returns generated by high-beta portfolios. In other words, the model has a low-beta bias. The extent to which the SL CAPM underestimates returns to low-beta portfolios is both statistically and economically significant.

As an example, we estimate that the lowest-beta portfolio of the 10 portfolios that we construct to have a beta of 0.54 – marginally below the midpoint of the AER's range for the equity beta of a regulated energy utility of 0.4 to 0.7. Our in-sample results suggest that the SL CAPM underestimates the return to the portfolio by 4.90 per cent per annum.'[413]

As Malko's report explains, there are two paths that can be followed to get to the bottom of why and how the SL-CAPM under-estimates the return for low beta stocks and both paths lead to the same place.

The first path is to consider the theoretical considerations to identify the problem, propose a solution and then test it empirically. The AER's initial discussion paper for the Rate of Return Guidelines articulated a firm preference for approaches with a sound theoretical explanation rather than an empirical one and we therefore consider this path first.[414] SFG have explained how the Black-CAPM relaxes the unrealistic assumption of the SL-CAPM that investors can borrow and lend at the risk free rate. When this theoretical improvement is made and the model is implemented, the effect is to raise the intercept (ie, the return on a risk free asset) and flatten the curve depicting the returns related to risk.

In the US, regulators have been content to take another path, focusing on empirical observations that the SL-CAPM under-rewards low beta stocks and making adjustments reconciles the SL-CAPM with the observed results. Malko explains that:

> *'I have been asked to comment on the correctness or otherwise of the statement in the Australian Energy Regulator's (AER) Final Decision, ActewAGL distribution determination 2015-16 to 2018 -19 - Attachment 3 - Rate of Return document:*
>
> > *"There is little evidence that other regulators, academics or market practitioners use the Black CAPM to estimate the return on equity. In particular, regulators rarely have recourse to the Black CAPM" at page 3-256.*
>
> *As I have explained above, although there is little explicit reference to the Black CAPM, in practice the use in the U.S. of the Empirical CAPM by financial analysts both within and outside energy regulatory processes is essentially to the same effect.'*[415]

Marko explains how the regulators give effect to the Empirical CAPM as follows:

> *'The regulators who have been presented with ECAPM evidence have considered it along with evidence from the DGM or DCF and Sharpe CAPM. The results from*

Networks and Untied Energy; June 2015 and SFG Consulting; *The required return on equity for regulated gas and electricity network businesses;* May 2014.

412 CEG Consulting; *Estimation of, and correction for, biases inherent in the Sharpe CAPM formula, A report for the Energy Networks Association Grid Australia and APIA*; September 2008; page 21.

413 NERA; *Empirical Performance of the Sharpe-Lintner and Black CAPM*; February 2015.

414 AER; *Better Regulation, Rate of Return Guidelines, Issues Paper*; 18 December 2012 (word version); page 15.

415 Malko; paragraphs [6.4] and [6.5]; page 8.

all these approaches have been recorded in the decisions and the selection of a particular figure has been made following that consideration.'[416]

The following are examples of regulatory processes in which models with a higher intercept and flatter curve have been considered:

Table 13.4: Use made by regulators of the Zero-Beta and Empirical CAPM

Regulator	Industry	Application	Citation
New York Public Service Commission, 2009	Electricity distribution	50/50 weighting. 'Traditional' CAPM/zero-beta CAPM paragraph 56.	Proceeding on Motion of the 2009 Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service; Petition for Approval, Pursuant to Public Service Law, Section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers 2009 N.Y. PUC LEXIS 507.[417]
New York Public Service Commission, 2007	Gas distribution	50/50 weighting. Average of traditional CAPM results and zero beta CAPM result paragraph 20.	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service 2007 N.Y. PUC LEXIS 449; 262 P.U.R. 4th 233.[418]
New York Public Service Commission, 2006	Gas and electricity distribution	50/50 weighting. Average of traditional CAPM result and zero beta CAPM result paragraph 19. NB: this decision changed the weighting from 75/25 to 50/50, the previously accepted weighting following the approach in the Generic Finance case.	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service; Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service 2006 N.Y. PUC LEXIS 227; 251 P.U.R. 4th 20.[419]

[416] Ibid; paragraph [5.5]; page 7.

[417] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service; Petition for Approval, Pursuant to Public Service Law, Section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers* 2009 N.Y. PUC LEXIS 507.

[418] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service 2007 N.Y.* PUC LEXIS 449; 262 P.U.R. 4th 233.

[419] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service; Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service 2006* N.Y. PUC LEXIS 227; 251 P.U.R. 4th 20.

Regulator	Industry	Application	Citation
Oregon Public Utility Commission, 2001	Electricity distribution	Zero-beta is used to contrast with S-L CAPM 'as beta decreases, the cost of equity decreases by less than the Sharpe-Lintner CAPM model suggests. This is important, …, because it means the costs of equity for utilities with betas of less than 1 are closer to the cost of equity for an average risk stock than is shown by the Sharpe-Lintner CAPM model. Under this model, the required return for the risk-free asset is expected to be higher than the return on Treasury bills.' Paragraph 20 'While the results in this case cast further doubt on the validity of Staff's CAPM methodology, we do not believe that CAPM should be rejected in its entirety. We continue to believe that, in certain cases, CAPM analyses may provide a useful and reliable addition to the DCF results for determining cost of equity.' Paragraph 23. CAPM given no weight, DCF preferred.	In the matter of PacifiCorp's Proposal to Restructure and Reprise its Services in Accordance with the provisions of SB 1149. 2001 Ore. PUC LEXIS 418; 212 P.U.R. 4th 379.[420]

An empirical inspired correction is sufficient for the US regulators. However, if a theoretical explanation were sought for what the Empirical CAPM does, it is that the SL-CAPM suffers from the above unrealistic assumption concerning the ability for investors to borrow and lend at the risk free rate.

In summary, whether the Black-CAPM or an Empirical CAPM nomenclature is used, the estimated return on equity for our business should give weight to a capital asset pricing model that raises the intercept and flattens the risk-return curve relative to the SL-CAPM. By including the Black-CAPM, Gray and Hall's multi-model approach does this appropriately and we continue to consider that to be the appropriate approach to take.

---

[420] In the matter of PacifiCorp's Proposal to Restructure and Re-price its Services in Accordance with the provisions of SB 1149. 2001 Ore. PUC LEXIS 418; 212 P.U.R. 4th 379.

(h) Fama French and Continuous Improvement in CAPM methods

This model in relation to which a Nobel prize[421] has been awarded, is newer than the other two CAPM models.

The AER's Preliminary Determination gives no weight at all to the Fama French model. Handley again justifies the AER's approach by asserting that the rate of return is concerned only with variables that are unequivocally proved to be ways to quantify risk and not with a more general search for a commensurate return:

> *'[E]mpirical evidence of a value effect is not sufficient on its own to justify a claim for additional compensation relative to the Sharpe-CAPM.*
>
> *The key point is that we do not have a clear understanding of what the value effect represents. This uncertainty is critically important in the current context because it means that the value effect does not necessarily reflect risk, whereas the allowed rate of return objective is clear that risk is the key determinant of the rate of return.'*[422]

For the reasons discussed above, Handley's approach construes the rate of return objective too narrowly and a model that behaves strongly in quantifying the market rate of return is ideal for setting a commensurate rate of return and should not be excluded on the basis that there is some argument as to whether or not its parameters are solely a measure of risk.

The Nevada State Controller, Ronald L. Knecht is an experienced former energy regulator who has consistently used the Fama French model in his work. He states:

> *'[W]hile there is still some apprehension about the use of the FF3F Model it has been recognised in at least three states, Massachusetts, Delaware and Nevada, when used in conjunction with other models to produce an arithmetic mean as an estimate. This approach ensures that factors that are ignored by one model are adequately addressed. Because the FF3F model is fairly new relative to other models I am not aware of any jurisdiction that has endorsed it exclusively or adopted allowed rates of return based expressly on it. Instead, the tradition in the United States is for regulatory decisions to review (or even just list) all the evidence in the record and then, subjectively balancing the merits and results of all of it, to arrive at a final conclusion as either a range of reasonableness or a point estimate.'*[423]

Despite being the newer model, since the turn of the century the Fama French Three Factor model has been part of the evidence in a number of state regulatory proceedings in the United States, including:

1) Before the Massachusetts Department of Telecommunications,[424] Mr Hunt (an expert witness) cites the Fama French study as demonstrating the relationship between company size and stock returns.

---

[421] *Eugene Fama is the 2013 recipient of the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel the Nobel Prize in Economics), Eugene F. Fama- French". Nobelprize.org. Nobel Media AB* 2014. Web. 15 Mar 2015. <http://www.nobelprize.org/nobel_prizes/economic-sciencesllaureatesl20 131fama-facts.html>

[422] *Handley, JC; Advice on the Rate of Return for the 2015 AER Energy Network Determination for Jemena Gas Networks, a report prepared for the Australian Energy Regulator*; 20 May 2015; page 6.

[423] *Knecht;* paragraph [4.6]; page 3.

[424] *Moul, Paul R.; 'Direct Testimony of Paul R. Moul, Managing Consultant, P. Moul & Associates, Concerning Cost of Equity,' Commonwealth of Massachusetts Department of Telecommunications and Energy;* October 17 2005; page 50.

2) Before the California Public Utilities Commission,[425] Mr Hunt (an expert witness), used the Fama French Three Factor model and calculated a cost of equity of 14.0 percent in September 2005; using the CAPM, Mr Hunt calculated a cost of equity of 12.55 percent. In this proceeding, the Fama French Three Factor model returned a result that was 145 basis points above that from the CAPM.

3) Before the Delaware Public Service Commissioner[426], Artesian Water Company led evidence that included Fama French model results. [427] The Commissioner accepted that evidence without reservation.

4) Mr Ronald Knecht (an expert witness for the Nevada Public Utilities Commission)[428] proposed a return on equity of 10.28 per cent that was calculated as an arithmetic mean of four components. He applied two discounted cash flow (DCF) estimates, a 2CAPM/FF3F model average, and one risk premium estimate. A hearing was held before the Public Utilities Commission of Nevada in April 2006. Mr Knecht stated that this approach was superior to relying only on the average of DCF models, because the CAPM, FF3F, and 'capital appreciation and income' (CA + I risk premium) methods used basic cost of capital input data differently from the DCF models. The overall result for the 2CAPM/FF3F was reported to be 10.13 per cent. The outcome of 10.13 per cent was comprised of a result from the CAPM with a 'Value Line' beta of 10.45 per cent, a result from the CAPM using an Ibbotson beta (with size adjustment) of 8.25 per cent, and a result from the Fama French Three Factor model of 11.63 per cent. The evidence was considered by the Public Utilities Commission of Nevada in April 2006.

5) On a separate occasion, in July 2007, Mr Knecht acted on behalf of the Nevada Public Utilities Commission[429] and again used the Fama French Three Factor Model to assess the rate of return on equity. He obtained a result for an average energy utility of 11.39 per cent. The average of two CAPM methods and the FF3F model was 11.13 per cent. On both of these occasions, the Nevada Public Utilities Commission accepted Mr Knecht's Fama French evidence without reservation. [430]

6) On another occasion in December 2014, Mt Knecht gave expert evidence (which included results from the Fama French model) before the California Public Utilities Commission. Whilst the Commission observed that the Fama French model had previously been rejected by the California Public Utilities Commission, the Commission recognised that the Fama French model has 'gained great currency in investment practice'. [431]

---

[425] *Application of Pacific Gas and Electric Company for Authority to Establish its Authorized Rate of Return on Common Equity for Electric Utility Generation and Distribution Operations and Gas Distribution for Test Year* 2006. (U 39 M); Application of Southern California Edison Company (U 338-E) for Authorized Capital Structure, Rate of Return on Common Equity, Embedded Cost of Debt and Preferred Stock, and Overall Rate of Return for Utility Operations for 2006; Application of San Diego Gas & Electric Company (U 902-M) for Authority to: (i) Increase its Authorized Return on Common Equity, (ii) Adjust its Authorized Capital Structure, (iii) Adjust its Authorized Embedded Costs of Debt and Preferred Stock, (iv) Increase its Overall Rate of Return, and (v) Revise its Electric Distribution and Gas Rates Accordingly, and for Related Substantive and Procedural Relief 2005 Cal. PUC LEXIS 537; 245 P.U.R.4th 442.

[426] *In the matter of the application of Artesian Water Company, Inc: for an increase in water rates* 2003 Del PSG LEXIS 51.

[427] Ibid; at [8].

[428] *Application of Sierra Pacific Power Company for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto; Application of Sierra Pacific Power Company for approval of new and revised depreciation rates for electric operations based on its 2005 depreciation study*, 2006 Nev. PUC LEXIS 91 at [63].

[429] *Application of NEVADA POWER COMPANY for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.* 2007 WL 2171450 (Nev. P.U.C.).

[430] See *Application of NEVADA POWER COMPANY for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly thereto. 2007 WL 2171450 (Nev. P.U .C.) at [1 02]; and see Application of Sierra Pacific Power Company for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto; Application of Sierra Pacific Power Company for approval of new and revised depreciation rates for electric operations based on its 2005 depreciation study*, 2006 Nev. PUC LEXIS 91 at [63].

[431] *Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2013 and to Reset the Annual Cost of Capital Adjustment Mechanism 2014 Cal. PUC LEXIS 622 at [7], citing*

7) Mr Hayes an expert from San Diego Gas & Electric used the FFM model in his testimony before the California Public Utilities Commission in May 2007. [432] Hayes calculated a return on equity of 13.89 per cent using the FFM, with a value of 11.73 per cent obtained using the CAPM.

In his testimony before the Californian Public Utilities Commission Gary Hayes notes:

> *'[T]he California Public Utilities Commissioner Bohn stated after the January 2007 cost-of-capital workshop: The commission should remain open to receiving evidence from new additional models should parties wish to provide such. We should always welcome new and better tools and ways of tackling problems.'*
>
> *…*
>
> *'First, the FF model is not a new, untested formula dropping in from academia. It has behind it a solid track record of research and has been the topic of extensive debate ... Nowadays, the FF model is used routinely by financial economists as they research investments, returns, and relative performance, as it is a useful tool with which to interpret return data on a wide number of asset types ... Use of the FF model is not limited to just the halls of the academy; it has expanded into the investing world as well . .... Other professional practitioners have begun to utilize the FF model. Valuation experts now add FF results to fairness opinions issued in mergers-and acquisitions transactions. Noteworthy is the Delaware courts' acceptance - and in one case, utilization- of FF evidence in asset-valuation disputes .... From the perspective of the everyday ROE analyst, the FF model is very accessible ... . Aside from its three California appearances, the FF method has also made its debut in Massachusetts and Nevada .... The Commissioner asked [the witness] whether FF is more accurate or useful than old standards. Accuracy, when measured as an equation's ability to predict returns (called R2 by statisticians) is improved by the FF factors ... Therein lies the model's usefulness as a cross check on its sibling, the CAPM.'*[433]

The cases on point suggest that increasingly more companies are using the Fama French model as a source of additional data.

The Guideline, however, takes the approach that although the Fama French model is 'relevant', it should play no part whatsoever in the establishment of the allowed rate of return. In SA Power Networks' view, the AER's rejection of the model is unfounded.

If the Fama French Three Factor model is wholly excluded from the analysis, then there will be no other model that specifically addresses the downward bias for value stocks. As SFG Consulting notes:

> *'Our view is that if the Fama-French model is not given any consideration by the AER, then the estimated cost of equity will be understated. If we were to rely solely upon the Sharpe-Lintner CAPM, populated with a regression-based estimate of beta, we would adopt a second-best solution, because we would ignore the empirical evidence that the HML factor proxies for risk.'*[434]

Application of Southern California Edison Company (U338E) for Authorized Cost of Capital for Utility Operations for 2008; and Related Matters 2007 Cal. PUC LEXIS 593 at [5.2.5].

[432] *Testimony of Garry G Hayes on behalf of San Diego Gas and Electric before the California Public Utilities Commission 2007*; page 19.

[433] Ibid; pages 12-15.

[434] SFG Consulting; *The Fama-French Model; Report for Jemena Gas Networks, ActewAGL, Ergon, Transend, TransGrid and SA Power Networks*; 13 May 2014; page 3.

Finally, we note that the AER's consultants have sought to suggest that because Fama and French continue to build on their previous work[435] by seeking further refinements the three factor model should be rejected in favour of the original SL-CAPM. Maintenance of this position is illogical. It is equivalent to suggesting that even though improvements in safety and performance are continually being found, the aviation industry should continue to use only the Wright Brothers' original aircraft.

(i) Summary

This submission summarises a wealth of additional evidence to support the necessity to move away from the sole or predominant reliance on the SL-CAPM when setting our allowed rate of return for equity. There is extensive support for the use of each of the DGM/DCF, Black-CAPM and Fama French Three Factor Model *concurrently with* the SL-CAPM.

In this respect we do not consider there to be any valid reason to depart from our Original Proposal and when the AER's Preliminary Determination is revoked and substituted with the Final Determination, that determination should employ SFG Consulting's multi-model approach as we initially proposed.

For the reasons set out above, we continue to support the use of Gray and Hall's multi-model approach which, for our illustrative 'place holder' averaging period in February 2015, they estimate our return on equity allowance should be calculated[436] using the following figures:

SL-CAPM	9.28%
Black CAPM	9.89%
Fama French model	9.88%
Dividend discount model	10.29%

Our Original Proposal was based on the weighted average recommended by Gray and Hall which, on our averaging period deliver the following result of 9.91%. Their weighting approach starts by assigning each model 25% but then makes adjustments to account for the fact that there are common elements to the SL-CAPM and the Black CAPM. Their weighting scheme addresses the issue of 'double counting' that could otherwise be said to arise if each of the SL-CAPM and Black CAPM were given a full 25% each.

While we continue to consider that a thoughtful weighting approach would be best practice, we consider that the main issue of importance is to bring all the relevant models into use. The precise weightings is a matter of refinement that can be further considered or debated once a track record for the multi-model approach has built up. Therefore, in our Revised Proposal, we use a simple average of the results from the four models to deliver an estimate of 9.83% (see SFG Consulting, page 6) or 9.8% when rounded to one decimal place by the PTRM.

[435] Eugene F. Famma and Kenneth R. French; *'A five-factor asset pricing model'* (2015) 116 Journal of Financial Economics.
[436] SFG Consulting; *Updated estimate for the required rate of return on equity, Report for SA Power Networks*; 19 May 2015; page 6.

13.8 Gamma

13.8.1 SA Power Networks' Original Proposal

The value set for gamma is closely related to the return on equity because it adjusts permitted revenues in recognition that the benchmark entity would distribute imputation credits to its shareholder base. The continued equity allowance and gamma determination together determine the permitted returns that investors can earn in the regulated network business.

SA Power Networks' Original Proposal provided a thoroughly substantiated valuation for imputation credits of *at most* 0.25. The comprehensive analysis was primarily been undertaken by Professor Stephen Gray and Dr Jason Hall at SFG Consulting (who has now joined with Frontier Economics)[437] and Dr Simon Wheatley of NERA.[438]

As explained in Gray and Wheatley's work, dividend drop off studies tend to give 'high side' valuations compared with other market valuation techniques and by accepting the theta value of 0.35 that emerges from that technique, SA Power Networks' claim is a moderate, responsible claim that should be recognised as already a claim in which we have given the maximum ground that can reasonably be given while maintaining a fair and reasonable return for investors.

There is broad consensus amongst energy network businesses on this issue. The same supporting materials and submissions presented by SA Power Networks have also have been presented to the AER at the same time by other energy network businesses. In the AER's Preliminary Determination, the AER notes that in addition to the material that we submitted with our Original Proposal, there has been one additional report prepared by Gray and Hall[439] under a joint retainer for SA Power Networks and a range of other service providers and similarly by Wheatley.[440] The AER's Preliminary Determination correctly assumes that we support and rely on that report and we formally submit it to the AER for consideration with this revocation and substitution submission.

Gray and Hall recommend a gamma of 0.25 on the basis of multiplying:

- a distribution rate of 0.7; and
- a value for distributed imputation tax credits of 0.35 (often referred to as the theta) drawn from an updated dividend drop off study technique that has been honed and tested in multiple previous regulatory determinations.

NERA[441] corroborates each of these two elements and in particular explains why the value estimate is a 'high-side' estimate.

13.8.2 AER's Preliminary Determination

The AER's Preliminary Determination for SA Power Networks (and other AER preliminary and final determinations released at the same time) rejects the proposed gamma of 0.25 and, in its place,

[437] SFG Consulting; *An appropriate regulatory estimate of gamma*; May 2014; *Dividend drop-off estimate of theta, final report, Re Application by Energex Limited* (No 2) [2010] ACompT 7; 21 March 2011.
[438] NERA; *The Payout Ratio, A report for the Energy Networks Association*; June 2013.
[439] SFG Consulting; *Estimating gamma for regulatory purposes*, Report for Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausnet Services Directlink, Networks NSW (Ausgrid, Endeavour Energy and Essential Energy), Citipower, Powercor, ENERGEX, Ergon, SA Power Networks, Australian Gas Networks and United Energy; 6 February 2015.
[440] NERA; *Estimating distribution and redemption rates from taxation statistics*, A report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Ergon Energy, Powercor, SA Power Networks and United Energy; March 2015.
[441] NERA*; Do imputation credits lower the cost of equity*? Cross-sectional tests, A Report for United Energy; April 2015.

adopts a gamma of 0.4. The AER reaches this conclusion based on selecting the mid-point from a range of 0.3 to 0.5. Each of the data points that contribute to the AER's range was also derived from the multiplication of pairs of numbers – one representing a distribution rate (ranging from 0.7 for 'all equity' measures to 0.8 for 'listed equity' measures) and a tax credit utilisation rate (ranging from 0.43 to 0.68 for 'all equity' and 0.38 to 0.55 for 'listed equity').

The AER's Preliminary Determination suggests that the figure of 0.4 supported primarily by work undertaken by Lally[442] and Handley[443] but on closer examination (discussed below) their reports contradict each other and the AER's approach.

When the regulator sets gamma at a significantly higher level than the network business proposes, the effect is to substantially lower the effective permitted returns below the level proposed because it leads to an assumption in the post tax revenue model that the investors are obtaining more substantial value from the imputation credits they receive and consequently that lower revenues will be sufficient to recompense existing investments and maintain the attractiveness of further investments required in the network.

13.8.3 SA Power Networks' response to AER Preliminary Determination

For the reasons set out below, the AER's Preliminary Determination gamma of 0.4 is flawed and it needs to be revoked and substituted in the Final Determination by a figure of 0.25 in order to ensure that the returns are commensurate with the returns that investors can obtain in equity markets at large. Since lodging our proposal, Gray and Hall, and NERA, have each prepared reports addressing the AER's approach to gamma:

- A report by SFG Consulting; Estimating gamma for regulatory purposes; February 2015; and
- A report by NERA (Wheatley); Estimating Distribution and Redemption Rates from Taxation Statistics; March 2015.

The AER has recently published two additional reports by Handley[444] concerning gamma and the following two new reports summarise the key issues and responds to those reports:

- A report by Frontier; An appropriate regulatory estimate of gamma; June 2015; and
- A report by NERA (Wheatley); Estimating Distribution and Redemption Rates: Response to the AER's Final Decision for the NSW and ACT Electricity Distributors, and for Jemena Gas Networks; 22 June 2015.

There are two fundamental differences of view that explain how SA Power Networks' approach differs so substantially from that of the AER:

1) the first fundamental difference of approach concerns what is meant by the term 'value of imputation credits' in rule 6.5.3. SA Power Networks and its advisors have consistently contended that this term must mean the valuation revealed in openly traded equity markets. The reasons for this view are explained at section (a) below. By contrast, in a range of regulatory documents published over the past five years the AER and its consultants have advanced one, two, three and even more formulations of argument and explanation that seek to bridge the gap between the reference in the Rules to a 'value', on the one hand, and the AER's preferred measure of the redemption rate. The details of these issues are discussed at section (b) below.

---

[442] Lally; *The estimation of Gamma*, Report for the AER; November 2013.
[443] Handley; *Further advice on the value of imputation credits*, Report for the AER; 16 April 2015; and Handley; *Advice on the value of imputation credits;* 29 September 2014.
[444] Handley, *Advice on the NERA report estimating distribution and redemption rates from taxation statistics,* 20 May 2015.

2) The second fundamental difference of approach concerns the set of comparator businesses that should be used when establishing a benchmark distribution rate. There are two key differences. First, the AER takes the view that the data for the distribution rate and the data for the valuation of imputation credits need to be drawn from the same set of firms. However, arbitrage in traded markets ensures that there is a single economy-wide market equilibrium value for imputation credits but the distribution rate obviously differs between firms depending on the considerations driving their capital structures. Secondly, even if it were appropriate to look at a limited group of 'comparator firms' the AER's approach to selecting that subset is inconsistent over time and inconsistent with other aspects of its approach to rate of return regulation. In particular, the AER has taken a strong stand that the relevant 'benchmark efficient' network operator is a 'pure play', wholly domestic business that is not necessarily stock market listed. However, the only way that the distribution rate could be 0.8 is by applying primary weight to a small subset of the largest (and therefore multinational and diversified) listed firms which are not valid comparators for the purpose of estimating the distribution rate for the benchmark efficient entity. The details of the issues concerning the distribution rate are discussed in section (c) below.

There are also significant 'second order' differences of view between the AER approach and the analysis prepared by Gray and Hall, and Wheatley upon which SA Power Networks relies:

3) As explained in section (d), the only useful guidance that a *correctly implemented* redemption rate study can provide when estimating gamma is as an upper bound. Then, *even if* the AER's redemption rate approach were correct (or if a redemption rate estimate is calculated for the purposes of an upper bound check), Gray and Wheatley are of the view that the AER's implementation of that approach is flawed. This issue is discussed at section (e) below.

4) Similarly, while disagreeing with us that a market valuation should be taken, the AER is of the view that *even if* a market valuation is to be taken, there are criticisms of Gray and Hall's work that need to be addressed. Section (f) below addresses these points.

Section (g) draws together a summary of the above points.

In our view, the existing body of empirical work thoroughly supports a figure of no more than 0.25. We do not propose to submit any new studies at this time. However we are concerned that the AER's Preliminary Determination has not properly addressed the points that our experts and its own have made. Consequently we have asked Gray and Hall to prepare a report that revisits key aspects of the existing materials and which collates the various ways in which the body of evidence contradicts the AER's gamma estimate of 0.4 and that report is lodged with this Revised Proposal and the discussion below draws mainly on that report.

(a) Why must gamma represent a market valuation and not a redemption rate?

The regulatory structure has always bracketed together the regulatory determination of the return on capital and the estimate of gamma. For example, the Rules require the AER to address both issues in the Rate of Return Guidelines. This is not surprising. If the regulatory system establishes an efficient rate of return for a benchmark network service provider from the prevailing market prices in traded debt and equity markets, so too must the gamma.

Indeed if the gamma is determined not from market data but from a 'conceptual analysis' that causes the regulator to diverge from the actual market based valuation a mismatch will necessarily arise between regulatory allowances and investors' investment return requirements and this will necessarily distort investment decisions positively or negatively, either way to the long term detriment of consumers.

As Gray and Hall's report explains:

> *'In the regulatory setting, the regulator first estimates the return that shareholders' require and then reduces that according to the estimate of gamma. For example, suppose the regulator determines that shareholders require a return of $100 and that those shareholders will receive imputation credits that are worth $20 to them. The regulator would then allow the firm to charge prices so that it can pay a return of $80 to the shareholders. That is, the regulator's estimate of gamma determines the quantum of the reduction in the return that the firm is able to provide its shareholders by other means (dividends and capital gains).*
>
> *If, for example, the regulator's assessment of the value of imputation credits is greater than the true value of imputation credits to shareholders, the shareholders will be under-compensated. In this case, the reduction in other forms of return (dividends and capital gains) will exceed the true value of the imputation credits.*
>
> *Thus, when estimating gamma, the appropriate question to consider is this: what is the quantum of dividends and capital gains that shareholders would be prepared to give up in order to receive imputation credits? It is precisely this question that is addressed by market value studies that seek to quantify the relative value (to investors in the market for equity funds) of dividends, capital gains, and imputation credits.*
>
> *The alternative is to reduce the regulatory allowance for returns from dividends and capital gains according to the proportion of investors who may be eligible to redeem credits, rather than according to the value of those credits. This approach will inevitably result in investors being mis-compensated because there is no attempt to consider whether the value of what investors are required to give up (dividends and capital gains) is equivalent to the value of what they receive in its place (imputation credits).*
>
> *…*
>
> *In my view it is abundantly clear that there are three components to the return on equity – dividends, capital gains, and imputation credits – and that a greater assumed value of imputation credits will result in a reduction in the regulatory allowance that generates dividends and capital gains. This is precisely what occurs in Row 35 of the PTRM – the return that could otherwise be provided to equity holders is reduced by the regulator's assessment of the value of imputation credits. Any suggestion that the regulatory allowance that generates dividends and capital gains is independent of the regulatory assumption about imputation credits is erroneous.'*[445]

It is disappointing that an economic regulator such as the AER would not have faith in the market mechanism to deliver a valuation and that it would prefer its own 'conceptual' valuation.

Indeed in amending the meaning of gamma in the NER and inserting the definition in the National Gas Rules, the AEMC did not raise any concerns with the regulatory approach that had developed in estimating gamma which, up to that point, had amounted to a market value. Indeed the word change was a move to bring the Rules into line with regulatory practice.

[445] Frontier; *An appropriate regulatory estimate for gamma*; June 2015; paragraphs [12], [16] and [18]; pages 8-9.

Pages 11 to 16 of Gray and Hall's report identify a series of re-formulations by the AER and its consultants over the last five years as to what the AER says gamma represents. Initially the AER's formulation appeared to over-look the express requirement in the Rules that gamma be a 'value'.

Network businesses responded by stressing the need for the gamma to be a 'value' and asserting that the plain meaning of 'value' imports the use of standard market valuation techniques. This precipitated a series of 'back and fill' attempts to articulate how the gap could be bridged between the word 'value' which appears in the Rules and the AER's preferred conceptualisation of gamma as a measure of the number of credits redeemed. This led first to several internally inconsistent semantic discussions ('we consider the word 'value' used in these contexts is being used in a generic sense to refer to the number that a particular parameter takes'[446] ; 'utilisation value'[447] and the 'pre-personal-tax and pre-personal-cost-value'[448]) and finally an assertion that the redemption rate might actually constitute a way to estimate value if that term is construed in a particular way ('the use of redemption rates as a measure of estimating the value of credits is driven by conceptual considerations and theory').

The fact that the AER has been unable to provide a consistent and coherent explanation of how its preferred redemption rate concept reconciles with the language in the Rules, and more significantly the notion that investors quite clearly seek market valued returns, strongly suggests that the approach it takes is unsafe.

The simple fact is that by taking redemption rates as the measure of gamma instead of studies of the value the market places on gamma, the AER's Preliminary Determination rejects the current definition in the Rules of gamma as a value.

(b) How the AER's theoretical or conceptual analysis is a confused and unsafe basis to estimate value

On pages 17 to 24 Gray and Hall's report details how:

- Lally's theoretical conception rests on a demonstratively incorrect assumption that there is no foreign ownership of Australian equity, and which is inconsistent with the way in which all other WACC parameters are estimated;[449]
- Handley's theoretical conception is inconsistent with core theoretical underpinnings of the CAPM which the AER uses as the foundation model for establishing the return on equity (ie that investors will determine the composition of their domestic and foreign investment portfolios in isolation from each other);[450]
- Handley does not appear to be able to clearly reconcile his current work with his former writings in that he simultaneously asserts that '[gamma] should not exceed its redemption value' and that 'using 'upper bound' in this context was unnecessary and confusing';[451]
- That the above two experts' approaches are demonstrably inconsistent with each other (in that the former does not conceive of foreign ownership while the latter does);[452]

---

[446] AER; *TransGrid Final Decision*, Attachment 4, page 30.
[447] AER; *Jemena Gas Networks Draft Decision*, Attachment 4, page 17.
[448] AER; *TransGrid Final Decision*, Attachment 4, page 47.
[449] Frontier; *An appropriate regulatory estimate of gamma*; June 2015, paragraphs [59-60], page 17.
[450] Frontier; *An appropriate regulatory estimate of gamma*; June 2015, paragraphs [61-63], pages 17-18.
[451] Presumably what Professor Handley means is that the redemption rates are in fact an upper bound but also he is of the view that the redemption rate will be the primary influence on an investor's valuation and that the valuation would not differ significantly below it but if that is indeed what was meant it could have been more easily stated and the first half of his view remains an important point in support of SA Power Networks' approach in Frontier Economics; An appropriate regulatory estimate of gamma, June 2015, paragraph [92], page 24.
[452] Frontier; *An appropriate regulatory estimate of gamma*; June 2015; paragraph [67]; page 18.

- That both the experts disagree with the approach taken by the AER (eg Lally explicitly states that key aspects of the AER's approach is 'not correct' and that he does 'not agree');[453] and
- That the AER has inappropriately interpreted Lally's 'second preference' as muted support for the AER's approach which is of a conceptual or theoretical nature when it is merely an observation that although the AER's approach is conceptually inconsistent with Lally's approach, it happens to deliver the second closest numeric result to Lally's own method.[454]

We note that since Lally articulated his criticisms of the AER's approach on gamma, the AER has ceased to publish any further advice from him while continuing to rely on Lally's earlier work.

Because the value of gamma is so important, it is incumbent upon the AER to reveal all of the advice that it has received from this author on this issue. Our advisors requested that any further work that Lally produced since October 2014 be disclosed to the public. The AER has resisted providing this information on the basis that it would involve reviewing approximately 7,400 pages of material which the AER considers would be a substantial and unreasonable diversion of resources. This response is disappointing. It suggests that there may indeed be a body of significant work from Lally on this matter. Having regard to the fact that the gamma (a) represents a material and substantial pecuniary value, and (b) an essential service consumed by the broadest cross-section of the community, this material should be disclosed without delay.

Further, Gray and Hall's report notes that the text book authored by Associate Professor Partington upon whose work the AER relies extensively in relation to establishing its preferred allowed rate of return for equity, defines gamma as 'the market value of franking credits as a percentage of face value' and that 'the market value of the franking credit is likely to differ from its face value'. Indeed Partington states that: 'We do not know exactly what the market value is, but the evidence suggests that franking credits are valued at a **significant discount to their face value**' which is inherently contradictory to the use of redemption rates as a 'value of imputation credits' or gamma.[455]

What emerges from the above observations are that there is only weak and contradictory support even amongst the AER's own finance experts for using the redemption rate as a point estimate of theta.

(c) If a robust redemption rate can be calculated it can only constitute an upper bound on the value of theta, not a point estimate

Investors cannot rationally value an imputation credit above its face amount – they will never realise more than 100% of its face amount. On the other hand, there may be many reasons including those identified previously by Gray and Hall as to why an imputation credit may be valued at less than 100% of the face amount. Therefore, if a robust measure of redemption rates can be calculated, it can only be of use for economic regulatory purposes as an upper bound on the estimate of theta. This is further explained by Gray and Hall's report.[456]

As noted above, Handley previously stated that he considered the redemption rate is an upper bound for gamma and he still considers that the theta '*should not exceed its redemption value, since this, by definition, represents the ultimate source of value of a credit'.*

(d) Flaws with the AER's redemption rate estimates

[453] Ibid; paragraphs [74-74]; pages 19-20.
[454] Ibid; paragraph [42-43]; pages 169-173.
[455] Brealey, Myers, Partington and Robinson (2000); page 168 in Frontier Economics; *An appropriate regulatory estimate of gamma*; June 2015; paragraph [97]; pages 24-25.
[456] Frontier; *An appropriate regulatory estimate of gamma*; June 2015; pages 23-24.

NERA explores why redemption rates will exceed, and markedly so, the value of those imputation credits:

> *'Imputation credits are of some use to domestic investors but are of little or no use to foreign investors. So the value that the market places on imputation credits distributed will largely depend on the impact that foreign investors have on equity prices.'*[457]
>
> *'[O]ne can expect the rate at which credits are redeemed to exceed, significantly, the impact of credits on the cost of equity, theta.'*[458]

And further:

> *'[T]he use of a domestic pricing model by the AER does not justify a presumption that the impact of foreign investors is restricted and that theta, consequently, take on a non-negligible value – contrary to claims that Handley makes in a September 2014 report.'*[459]

The Rules require the AER to deliver a reasoned determination. A frustrating aspect of the AER's Preliminary Determination is that it asserts that the AER is now considering a broader range of data than it did in the Guideline, without detailing how the different studies considered have actually produced a particular estimate of theta and in turn a specific value for gamma of 0.4. Instead, a range of statistics is used, with thetas ranging from 0.43 to 0.58 combined with two different distribution ratios of 0.7 and 0.8 to deliver a range for gamma.

Gray and Hall's latest report[460] also illustrates that the AER's methodology contains key internal inconsistencies when it comes to actually performing a redemption rate estimate:

- There is inconsistency as to whether the relevant redemption rate is a firm specific or market-wide parameter.
- Although the AER's Preliminary Determination states that it has taken into account tax statistic studies delivering numbers of 0.43, 0.45, 0.44 and 0.58, the AER's recent final determination for TransGrid states that its estimate is based on 'an imputation credit utilisation rate (theta) of 0.6'. A figure as high as 0.6 is only supported by one of the AER's statistics and only if it is rounded upwards to one decimal place. The other three statistics cited in the AER's Preliminary Determination all support a substantially lower number.

Gray and Hall[461] also note that the equity ownership model may quite reasonably over-estimate the actual redemption rate due to the 45-day rule. Although he does not himself estimate the size of any over-statement, because the necessary data is not available, he does note that Handley and Maheswaran provide an indication that it may be material.

In summary, if a redemption rate were used as the value of imputation credits (and we have explained above why this would be the wrong thing to do), such a redemption rate should be significantly below the 0.6 level that the AER appears to use.

---

457 NERA; *Estimating Distribution and Redemption Rates: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, and for Jemena Gas Networks, A report for ActewAGL Distribution, AGN, APA, AusNet Services, CitiPower, Energex, Ergon Energy, Jemena Electricity Networks, Powercor, SA Power Networks and United Energy*; 22 June 2015; page i.
458 *Ibid*; page ii.
459 *Ibid*; page ii.
460 Frontier; *An appropriate regulatory estimate of gamma*; June 2015; page 31.
461 *Ibid*; page 41.

(e) The AER's criticisms of Gray and Hall's valuation studies

The AER has asserted that there is 'new evidence' that means that very dated valuation studies should again be considered when taking a market value even though it had previously rejected them. The claimed 'new evidence' comprises just two sentences in a paper by McKenzie and Partington.[462]

By contrast, Gray and Hall[463] has provided a considerably more thoughtful analysis that explains why the newer, post 2000 based studies are strongly preferable bases to assess market value.

The Draft Determination for Ausgrid asserts[464] that there remain empirical estimation issues with Gray and Hall's work but in our view these points have already been answered by Gray and Hall[465] and, in many cases, also the Australian Competition Tribunal, and we do not propose to repeat those points in this submission.

The AER's Preliminary Determination asserts that Gray and Hall's drop off studies should be 'recalibrated' by dividing them upwards by an amount of 0.05. The idea of making an adjustment arises from the possibility that investors may value not only imputation credits but also dividends at less than their 'face value'. Gray and Hall have provided further analysis of whether this is an appropriate adjustment to make and on page 35 of their current report they do indeed provide a further explanation reaffirming why no adjustment should be made. The challenge here is to remember that a higher theta represents a lower return to investors. To explain the effects of the AER's adjustment, Gray and Hall consider a hypothetical in which an investor values dividends at only 90% of the face value. In summary, this hypothetical illustrates that:

> *'Rather than allowing a higher return, the AER proposed adjustment would result in a lower allowed return. The AER would propose that the 0.35 estimate should be divided by 0.9 to produce an adjusted estimate of 0.39. This higher theta would then result in shareholders receiving a lower return than they otherwise would. That is, rather than compensating investors for the lower value of dividends, the effect of the AER's proposed adjustment would be to compound the problem by reducing the amount of dividends that the firm is able to distribute. Thus, such an adjustment produces a perverse outcome.'*[466]

(f) Distribution rates

The AER's own Guideline uses a 70% distribution rate while the AER's Preliminary Determination[467] uses both 70% and 80% figures for the various data sets considered. Any departure from the Guideline figure requires a properly reasoned basis which has not been provided in the AER's Preliminary Determination instead asserting,[468] without explanation, that there is some form of 'internal consistency grounds' at play:

> *'As set out in the draft decisions and in section A.9.2 of this preliminary determination, we consider that there are good reasons – on internal consistency grounds – for using in certain circumstances an estimate of the distribution rate based on only listed equity. However the service providers did not comment on these reasons in their revised proposals.'*

[462] McKenzie and Partington; *Review of Aurizon Network's draft access undertaking*; October 2013; paragraph [134].
[463] Frontier; *An appropriate regulatory estimate of gamma*; June 2015; paragraph [134]; pages 33-34.
[464] AER; Ausgrid Draft Determination, Attachment 4; November 2014; page 23.
[465] SFG; *Estimating Gamma for Regulatory Purposes*; February 2015.
[466] Frontier; An Appropriate regulatory estimate for gamma; June 2015; page 38.
[467] AER Preliminary Determination Attachment 4; tables 4.1 and 4.2 at pages [4-18].
[468] AER *Preliminary Determination* Attachment 4; pages [4-17].

This revocation and substitution submission is SA Power Networks' first opportunity to comment on the alleged 'internal consistency grounds' and we do so as follows.

Superficially the notion of internal consistency is appealing to the eye and in many contexts (like the need for both the rate of return on equity and gamma to both be market based valuations if investors are to receive appropriate incentives to invest) there are strong grounds that can be articulated as to why two values have a relationship of 'internal consistency'. However, it is necessary to consider what the two allegedly 'consistent' concepts are measuring before jumping to the conclusion that a relationship of sameness should apply.

In this case, the two measures are very much independent concepts and there is no reason to suppose that the optimal data set used to measure them should be the same. Indeed there are strong reasons why the optimal data sets may differ when measuring the distribution rate and theta. The distribution rate is a measure of the proportion of a firm's earnings that it returns to shareholders in-period versus the earnings it retains to fund its capital requirements. This is obviously a question that is firm specific. Each firm will have different capital requirements and patterns for earnings. Just as the 60:40 debt to equity ratio is established as an optimal financing structure for a benchmark energy business, so too is the distribution decision.

By contrast, investors can effectively trade imputation credits via the purchase and sale of stocks and there is an extensive opportunity for arbitrage between the values of stocks in different industries and there is no reason to suppose there will not be a single prevailing equilibrium price for imputation credits.

In other words, the distribution rate is inherently firm specific while the same equilibrium market clearing value of distributed credits will be observable throughout the economy. NERA states:

> *'The distribution rate…is a firm specific parameter. One firm, after weighing up the costs and benefits of distributing credits, may decide to distribute all of the credits that have been created over some period. A second firm may rationally decide to distribute no credits – perhaps because it wishes to use internally generated funds to finance new projects.'*[469]

Gray and Hall's studies take a whole-of-stock-market dividend drop off analysis to ensure that there is a wealth of data contributing to a robust valuation of theta but there is no reason to suppose that a benchmark efficient entity optimal distribution rate would match that of, for example, a company running a television station. Putting it differently, investors can trade their holdings in both power companies and television stations to effectively purchase or divest imputation tax credits but the companies concerned will logically determine their distribution rates according to their capital investment needs.

At the very least, there is broad support for the notion that the distribution rate should be firm specific (even if there is debate about where to draw the theta value from). This is supported by the AER,[470] NERA,[471] Gray and Hall's report[472] and he also cites support from Lally.[473]

---

[469] NERA; *Estimating Distribution and Redemption Rates*: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, and for Jemena Gas Networks; 22 June 2015; page iii.

[470] AER; *TransGrid Final Decision*, Attachment 4; page 20.

[471] NERA; *Estimating Distribution and Redemption Rates from Tax Statistics,* A Report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Ergon Energy, Powercor, SA Power Networks and United Energy; March 2015; table 3.4; page 12.

[472] Frontier; *An appropriate regulatory estimate of gamma*; June 2015; paragraph [99-101]; page 26.

[473] Lally; *The estimation of gamma*, Report for the AER; November 2013.

The more important question, therefore, is what is the correct distribution rate to adopt in the context where it is acknowledged that the distribution rate is a firm specific parameter. The AER[474] has rejected the notion that the distribution rate should actually be determined by looking at energy network company stocks because the data set is small (which we agree with) and it is alleged that doing so might create an incentive to manipulate the distribution rate (which seems surprising). So the question is what is the next best source for a suitable distribution rate.

In our view, the appropriate rate is 70% for a number of key reasons:

- First, the 70% figure accords with our own views and experience operating an energy network business as to the efficient distribution rate if the network business was a stand-alone business.
- Second, the AER has decided[475] that the benchmark efficient entity is *'a pure play, regulated energy network business operating within Australia'*. As Gray and Hall's report[476] and NERA's work[477] explain, the top 20 Australian listed companies are predominantly multinational companies who are able to use dividends paid out of foreign profits to distribute a greater proportion of the imputation credits created from their domestic operations. It is not surprising that these firms have more than an 80% imputation credit distribution rate while other stocks are considerably lower. These top 20, predominantly multinational, listed entities are inappropriate comparators (at least unless their data is averaged with small firms in the economy who have low distribution rates). This list, for example, includes businesses with well known international profiles such as BHP Billiton, the ANZ Bank, Macquarie Group, Rio and Westfield Corporation, all of whom self-evidently have significant foreign earnings. When the top 20 firms are 'backed out' of the over-all data concerning listed equity the figure is close to 70%:[478]

  > *'The point is that any firm with foreign profits will be able to distribute more imputation credits than they would otherwise have been able to. The 20 largest multinational companies obviously have material foreign income and they would obviously be able to distribute fewer imputation credits without that foreign income.'*

- Third, if there is no better benchmark to use, the very broadest statistic is appropriate – that being the economy-wide distribution rate of 70%.

We note that the AER[479] has said that Handley has criticised SFG's analysis on the second of the above points as 'incomplete and over-simplified'. This criticism cannot be accepted where Handley's own analysis of the point is even briefer and incomplete and, in any event, the current report takes this analysis further.

---

[474] AER; Better Regulation, *Explanatory Statement*, *Rate of Return Guidelines;* December 2013 **(Explanatory Statement)**; page 164.
[475] Ibid; page 45.
[476] Frontier; *An appropriate regulatory estimate of gamma*; June 2015; paragraphs [111-118]; pages 28-29.
[477] NERA; Estimating Distribution and Redemption Rates from Tax Statistics, A Report for Jemena Gas Networks, Jemena Electricity Networks, AusNet Services, Australian Gas Networks, CitiPower, Ergon Energy, Powercor, SA Power Networks and United Energy; March 2015; table 3.4; pages 13 and 23; and NERA; Estimating Distribution and Redemption Rates: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, and for Jemena Gas Networks; page vii – "We believe that the AER's 2009 statement that a benchmark network service provider need be neither large and publicly listed nor publicly listed is correct. Thus we believe that Handley is wrong to advocate the use of a distribution rate that places a large weight on large publicly listed firms and no weight on private firms. It is difficult to see that there is a case for setting the distribution rate to be any different than the value accepted by the Australian Competition Tribunal in its 2010 decision and the market-wide value chosen in the AER's Rate of Return Guideline of 0.70. This value is based on a cumulative distribution rate computed using tax statistics aggregated across all companies – both private and public."
[478] Frontier; *An appropriate regulatory estimate of gamma*; June 2015; paragraph [109]; page 29.
[479] AER; TransGrid Final Decision, Attachment 4; page 66.

(g) Summary

When revoking and substituting the Final Determination in place of the AER's Preliminary Determination, the AER should replace the gamma of 0.4 with a gamma of no more than 0.25 because:

- The AER's equity ownership approach is flawed and poorly implemented;
- Rather, gamma must be set on the basis of a market based valuation;
- Gray and Hall's robust dividend drop-off studies deliver a value for theta of 0.35;
- The AER's criticisms and adjustments to Gray and Hall's work are flawed;
- Gray and Wheatley agree that amongst different market valuation methods, dividend drop-off studies tend to give high values for gamma;
- The AER's partial reliance on distribution rates of 80% are inconsistent with its conception of the benchmark firm and each of the legitimate measures are approximately 70%; and
- Combining a theta of 0.35 with a distribution rate of 70% gives a gamma of 0.25.

13.9 Return on Debt

13.9.1 SA Power Networks' Original Proposal

(a) The transition to the trailing average method

The transition to the trailing average method is without question the most significant issue concerning the debt allowance in the 2015-20 RCP for our business.

Although SA Power Networks has consistently put the position to the AER that the hybrid method was the efficient way to raise debt under the 'on the day' regulatory approach (and so too does the AER itself), we did not initially object to the AER's approach of phasing in the trailing average in the way described in the Guideline. Although we never accepted that it was a conceptually appropriate approach, we considered that on the prevailing market data at the time, this transition would deliver a reasonable approximation for the transition that a real electricity network business will have to go through in response to the adoption of the trailing average form of regulation.

Therefore, in our Original Proposal,[480] SA Power Networks accepted that the allowed return on debt could be determined by gradually moving from the 'on the day' method of determining debt to the trailing average method in a manner that was consistent with the AER's Guideline even though we did not consider this to be the correct approach conceptually.

At the time, SA Power Networks was focused on, and expressed, its strong concerns that the AER's approach to setting the equity allowance was depressing the over-all debt-equity blended allowed rate of return significantly below market rates.

However, since lodging our Original Proposal, the debt risk premium has fallen further[481] and this 'on the day' fall relative to efficient hybrid debt financing practices further depressed the over-all weighted average cost of capital relative to market rates. We realised that, to deliver a market based return, it would also be necessary to remedy flaws in the AER's approach on debt by bringing it back into alignment with the efficient hybrid debt financing practices of a benchmark efficient entity.

The mismatch arises because the AER's transition effectively substitutes an 'on the day' debt benchmark taken at a time when the debt risk premium is depressed [relative to an historical average] for the actual efficient costs of a benchmark efficient entity that reflects the costs of raising debt over the last 10 years. The AER has acknowledged that this would today have long-term debt with staggered maturities reflecting an average of interest rates for debt raised throughout the last 10 years with hedging of the base interest rate. The AER proposes to apply a significantly lower debt risk premium. Further, as the subsequent RCP commences, it would still be contributing a 50% weight to our debt allowance when, in reality, our debt was raised at higher prevailing costs.

On 30 January 2015, SA Power Networks provided a submission to the AER that advocated for a different approach to the establishment of the allowed rate of return for debt commonly referred to as the 'hybrid' approach. This approach would provide a transition path that a benchmark firm could in reality implement (and which, indeed, is the path that our treasury is most likely to follow).

[480] AER *Preliminary Determination* Attachment 3 at [3-338] – [3-339].

[481] The measure of the fall depends on whether onpage uses the RBA or Bloomberg's quoted numbers and which extrapolation method.

(b) Other issues

In our Original Proposal we also made the following proposals that have not been accepted by the AER. We explained that:

- the benchmark credit rating should be BBB not BBB+;
- there are other costs not properly recompensed under the Guideline approach such as the cost of the new issue premium; and
- the AER's extrapolation of the Bloomberg and RBA curves underestimates the allowances for a 10 year tenor for our averaging period and at many other times too.

In the interests of brevity we will not further discuss the issues upon which we agree with the AER. However, we note that in some of these areas, we do not agree:

1) with all of the RBA's reasoning (for example where the AER suggests that the true benchmark tenor may be somewhat less than 10 years); or
2) our Original Proposal explained that our agreement is based on the limited information available at the time of our proposals (such as the use of a 50:50 average of the Bloomberg and RBA data sources).

13.9.2 AER's Preliminary Determination

In the AER's Preliminary Determination, the AER reaffirmed that an efficient practice of a benchmark firm regulated under the previous 'on the day' method would have been to raise long-term debt on a staggered basis and hedge against movements in the base interest rate between the date debt is actually raised and the regulatory averaging period.

However, the AER rejected SA Power Networks' submission of 30 January 2015 and instead imposed the transition that it set out in its Rate of Return Guidelines. In doing so, the AER questioned whether we were able to 'amend our regulatory proposal' even though we did not do so when we lodged our 30 January 2015 submission.[482]

In the current regulatory process, there are four distinct avenues by which a DNSP such as SA Power Networks may express its views:

a. in the regulatory proposal itself (lodgement of which is provided for in Rule 6.8.2);
b. in information 'accompanying' the regulatory proposal (which a number of Rules recognise as a distinct category of material from the regulatory proposal itself – see rule 6.9.1(a)(3) and rule 6.11.1(b)(1));
c. in a submission lodged by the business during of the periods in which the AER invited submissions on the AER's Preliminary Determination (see rule 6.9.3(a)(5)); and
d. in the submissions in response to the revocation and substitution of the AER's Preliminary Determination (see rule 11.60.4(b) which expressly states that 'any person' may make a submission and which adds that <u>'Without otherwise limiting the manner in which the affected DNSP may make such submissions,</u> the affected DNSP may make a submission in the form of revisions to the *regulatory proposal* that it submitted to the *AER* in relation to the distribution determination referred to in paragraph (a).').

[482] AER *Preliminary Determination* Attachment 3 at [3-136].

In relation to (c) above, there is no explicit limitation preventing a DNSP from making a submission on its own regulatory proposal and, indeed, rule 6.11.1A(d) of the NER (which will come into effect at the next regulatory control period after the transitional arrangements expire) explicitly acknowledges that a DNSP might make submissions on a revised regulatory proposal both during and after the AER's invitation to make submissions has expired. In adopting clause 6.11.1A(d), the AEMC did not state that it was creating a new avenue for the regulated business to make submissions on its own proposal along with other interested parties – rather it was taken as given that this was so but that more machinery was required to spell out the AER's powers and obligations in relation to late submissions.

In this case, SA Power Networks chose to advocate for the hybrid transition method in a submission made during the consultation period on its Original Proposal, as it was entitled to do. That submission was not required to constitute a formal revision to the regulatory proposal and it did not purport to do so.

For completeness, it is worth noting that in our view we could have formally amended our regulatory proposal if we had chosen to do so.

However, the status of SA Power Networks' Original Proposal and 30 January 2015 submission are of secondary relevance now that the revocation and substitution process has commenced. Looking forward, our revocation and substitution submission reaffirms the need for the hybrid transition approach and we have amended our regulatory proposal accordingly. All stake-holders have been on notice as to our views since 30 January 2015 providing ample opportunity to test and comment on our approach.

In any event, the AER's Preliminary Determination did consider four possible options for transition including the hybrid method (which was one of the options rejected).

The key considerations were based on work by Lally. In summary, the AER summarises Lally's advice as follows:

> *'<u>The NPV principle is a fundamental principle of economic regulation</u>. The NPV principle is that the expected present value of a benchmark efficient entity's regulated revenue should reflect the expected present value of its expenditure, plus or minus any efficiency incentive rewards or penalties. In other words, departures from cost recovery are acceptable and desirable, so long as they are the result of management induced efficiencies or inefficiencies, rather than windfall gains or losses. Windfall gains or losses would result in a service provider being over- or under-compensated for its efficient costs. The building block model which the NER require us to use is based on this principle.'*[483]
>
> *'<u>[T]here is a strong connection between the NPV principle, the allowed rate of return objective and the NEL revenue and pricing principle of providing service providers with a reasonable opportunity to recover at least efficient costs.</u> Lally advised that each of these principles or objectives are equivalent. We therefore consider it is useful to assess the four return on debt approaches for consistency with the NPV principle.'*[484]
>
> *'A contentious issue in the current determinations is the timeframe over which it is appropriate to consider the impact of this change. In particular, in relation to providing a benchmark efficient entity a reasonable opportunity to recover its*

[483] AER Preliminary Determination Attachment 3 at [3-149].
[484] *Ibid*.

efficient financing costs, whether it is appropriate to consider the impact on the benchmark efficient entity over the life of its assets. Several service providers submit that the time horizon of our perspective must be confined to the 2014–18 period (for TransGrid) or the 2014–19 period (for ActewAGL, Ausgrid, Endeavour Energy and Essential Energy). Also, they submit that the approach to debt should not be determined by reference to the activities and investments of a benchmark efficient entity beyond the regulatory control period in question. <u>We disagree</u>.'[485]

'Below we discuss impacts on a benchmark efficient entity that arise from changing the method for estimating the return on debt. We discuss impacts that occur across regulatory control periods, <u>such as over the life of a benchmark efficient entity's regulated assets. We consider the NER require us to do so.</u> The NER refer to 'any' impacts on a benchmark efficient entity as a result of changing the return on debt methodology. The NER then give an example of one impact—the cost of servicing debt across regulatory periods. Accordingly, the NER indicates that it is appropriate to take a perspective across more than one regulatory period.'[486]

13.9.3 SA Power Networks' response to AER Preliminary Determination

(a) The evidence base upon which our submission is based

Since the Original Proposal and before the AER's Preliminary Determination was published, the following expert reports have been lodged with the AER:

- SFG Consulting; Return on debt transition arrangements under the NGR and NER, Draft report for Jemena Gas Networks, Jemena Electricity Networks and United Energy; 27 February 2015;
- CEG; Critique of the AER's JGN draft decision on the cost of debt; April 2015. This report identifies there is not a most efficient approach for estimating the cost of debt and advances the position that if a business is financed on a hybrid approach then the transition should be the hybrid; and
- Erik Schlogl; the AER's JGN draft decision on the cost of debt – a review of the critique by the CEG; 20 April 2015. This report corroborates CEG's report.

These reports were lodged by other businesses with the AER prior to the AER's Preliminary Determination but they have not yet formed a formal part of our submissions. They conclude that if the benchmark entity finances in the way the AER describes then the hybrid approach is the correct approach to setting the cost of debt in the forthcoming RCP.

Additionally, since that time:

- we have procured an additional report by Dr Hird (CEG; Transition to the trailing average rate of return on debt, Assessment and calculations for SAPN; June 2015), to address amongst other issues, whether the 'windfall gain' is as Lally suggests, if the hybrid transition path were followed; and
- Dr Hird produced a memorandum (CEG, Extrapolation of the Bloomberg curve to 10 years, 19 June 2015) with his preliminary assessment of issues arising from Bloomberg's new 10 year curve.

(b) The transition to the trailing average method

[485] *Ibid* at [3-150].
[486] *Ibid* at [3-134].

The base-line for understanding whether and what sort of transition might be appropriate is to understand the economic effect of the former regulations. Dr Hird describes them as follows:

> *'The previous "on-the-day" approach to setting compensation for the cost of debt was flawed, including, in my view, being inconsistent with the newly formulated allowed rate of return objective. It did not reflect the costs of a viable debt management strategy and, every time a regulatory decision was made, a business and its customers were subject to what was, in effect, a roll of the dice.'*[487]

As noted above, the AER's Preliminary Determination acknowledges that the benchmark firm regulated under the 'on the day' method would have raised long term debt on a staggered basis with hedging for movements in base interest rates to minimise (but not eliminate) the effect of movements in base interest rates between the regulatory averaging period and the time debt was actually raised on the difference between the allowed and actual costs of debt.

Despite this, the AER proposes to set an allowed rate of return during the RCP that in the words of Dr Hird, 'rolls the dice one final time' by starting the RCP with another 100% 'on the day' allowance that will only progressively be replaced over the next 10 years.

Even as the subsequent RCP commences this final 'roll of the dice' will still continue to determine 50% of our debt allowance. By using this data for 10 years when previously the 'on the day' data was used for a maximum of 5 years, this final roll of the dice is akin to a 'double down' gamble. The real problem with the transition, however, is that the dice are loaded against the business. We know that interest rates (both base rates and DRP) are lower now than they were over the last 10 years over which debt was issued.

Recall, that an efficient benchmark business would have a staggered debt portfolio that includes bonds issued at much higher interest rates than currently prevail so we know with almost complete certainty that the allowance set according to the AER's methodology will not cover the efficient costs of the benchmark firm over the next 10 year period until the transitionary final 'roll of the dice' has completely worked its way out of the system.
Dr Hird has examined the AER's reasoning for imposing this significant under recovery and he summarises it as follows:

> *'[T]he AER's only substantive reason for not doing so is to impose a prospective loss on businesses in order to offset what it argues are "windfall gains" made from the application of the on-the-day approach.'*[488]

For both legal and economic reasons we cannot agree with the AER's approach, based on Lally's advice, to interpreting the NEL and Rule 6.5.2.

Inconsistency with the regulatory requirements

First, the NPV concept referred to by Lally is not explicitly referred to in name or concept anywhere in the NEL or the NER. Nor are we aware of any Court or Tribunal case that has recognised that the NPV principle is implicit in the requirements of the economic regulatory instruments. Although it may be the case that in certain circumstances Lally's NPV principle would lead to the same outcome as applying the Rate of Return Objective, the National Electricity Objective or the Revenue and Pricing Principles, there is a significant danger that applying the NPV principle instead of the legal

---

[487] *Ibid*; page 9.
[488] *Ibid*; page 10.

requirements as drafted may lead to a result that is inconsistent with those legal standards. For the reasons set out below, there is a risk that applying Lally's NPV principle would lead the AER into error where the timeframe over which Lally advocates that the analysis should be undertaken is at odds with the timeframe for decision making required by the NEL and the NER.

Second, it cannot be that Lally's NPV concept can be simultaneously 'equivalent' to both the rate of return objective and the revenue and pricing principle that requires businesses to be given a reasonable opportunity to recover efficient costs because those two legal standards are distinct and separate considerations. In recognition of the need to foster efficient investments, the Revenue and Pricing Principles sets out a principle that establishes a *minimum* ability for regulated businesses to have a reasonable opportunity to recover *at least* their efficient costs. This Revenue and Pricing Principle is to be taken into account by the AER *when exercising an economic regulatory function* and the only such functions of the AER concern the making of regulatory determinations applying to defined RCPs.

By contrast, the rate of return objective which must be satisfied *at the time of the regulatory determination* applying to the return on equity and debt *for the regulatory control period*, that the allowed rate of return should be commensurate with the efficient financing costs of a benchmark efficient network service provider. Additionally, there is a recognition that there may be impacts (most obviously additional costs arising from the change) that a business may experience when there is a change of regulatory approach and this impact should be taken into account in the allowed rate of return for debt. It is conceivable that there may also be some impacts of a change in regulatory approach that enable the business to make savings but it stands to reason that these are likely only to arise concurrently with additional costs and so they would be taken into account as a smaller net cost impact.

The rate of return objective targets an optimal debt allowance – neither more nor less than the target – and it is therefore quite distinct from and not equivalent to the concept that the network business should be provided with at least a reasonable opportunity to recover its efficient costs.

As the AER's Preliminary Determination itself illustrates, the NPV principle asserts both a minimum and a maximum and in that respect it is similar to the allowed rate of return objective but dissimilar from the Revenue and Pricing Principle. Indeed, in the AER's Preliminary Determination it is asserted that the NPV principle requires that the allowance that would otherwise be permitted be *reduced* to remove an alleged windfall gain that a *minimum* revenue requirement can, by itself, never require. In other words, a Revenue and Pricing Principle which sets out a minimum cannot be 'equivalent to' either the rate of return objective nor the NPV principle which each establish a target that is neither a minimum nor a maximum.

Further, the NPV principle is said to apply over the life of the regulatory assets that in SA Power Networks' case include many assets that predated the NEM and modern economic regulation. By contrast, the allowed rate of return objective and the Revenue and Pricing Principle must be applied at the time of the regulatory determination in relation to the regulatory control period.

More specifically, Rule 6.12.1 requires the AER to make a determination concerning the allowed rate of return at each regulatory determination for a defined RCP in accordance with Rule 6.5.2. In this case, that period is the period 2015 to 2020. Consistent with CPI-X regulation, the Rules are written with all the relevant concepts expressed in the present tense to apply on their terms at the time of the determination – not over an extended retrospective period. Rule 6.5.2(b) provides that:

> *'The **allowed rate of return** is to be determined such that it achieves the **allowed rate of return objective.**'*

Rule 6.5.2(c) provides that:

> *'The **allowed rate of return objective** is that the rate of return for a **Distribution Network Service Provider** is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the **Distribution Network Service**.'*

Rule 6.5.2(h) provides that:

> *'The return on debt for a **regulatory year** must be estimated such that it contributes to the achievement of the **allowed rate of return objective**.'*

Rule 6.5.2(j) provides that:

> *'Subject to paragraph (h), the methodology adopted to estimate the return on debt may, without limitation, be designed to result in the return on debt reflecting:*
>
> *(1) the return that would be required by debt investors in a benchmark efficient entity if it raised debt at the time or shortly before the making of the distribution determination for the regulatory control period;*
>
> *(2) the average return that would have been required by debt investors in a benchmark efficient entity if it raised debt over an historical period prior to the commencement of a regulatory year in the regulatory control period; or*
>
> *(3) some combination of the returns referred to in subparagraphs (1) and (2).'*

Additionally, Rule 6.5.2(k) [489] provides that:

> *'In estimating the return on debt under paragraph (h), regard must be had to the following factors:*
>
> *(1) the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the allowed rate of return objective;*
>
> *…*
>
> *(3) the incentives that the return on debt may provide in relation to capital expenditure over the **regulatory control period**, including as to the timing of any capital expenditure; and*
>
> *(4) any impacts (including in relation to the costs of servicing debt across **regulatory** control **periods**) on a benchmark efficient entity referred to in the **allowed rate of return** objective that could arise as a result of changing the methodology that is used to estimate the return on debt from one **regulatory control period** to the next.'*

Third, the Lally approach is a significant abrogation of the 'guarantee' inherent in the RPI-X form of regulation to the effect that once a RCP is passed, subject to any explicitly defined carry-over incentive, the past revenues cannot be clawed back and nor can past cost over-runs be claimed. This is the fundamental economic principle that would inform the interpretation of how the Rules should apply across periods.

[489] The Rules, Rule 6.5.2(k); page 664.

Even if there were a windfall gain to be had, that gain would have occurred in the previous RCP and under the Australian 'CPI-X' form of regulation reducing a firm's prospective allowance based on past over-recovery is not permitted. CPI-X regulation was adopted into Australia from the United Kingdom where it was known as 'RPI-X' regulation. This form of regulation was devised by now Professor Littlechild when he was a civil servant in the UK's Royal Treasury working on the privatization of British Telecom in the mid 1980s.

The distinguishing feature of RPI-X regulation,[490] in the words of Littlechild himself, is that the business' allowed revenues are established for the full RCP of approximately five years (four at the time Littlechild initially invented the system) and this return is 'guaranteed'[491] for the business over the life of the regulatory proposal regardless of whether in fact its costs are higher or lower than the regulatory allowance established.

This is why even today the regulatory structure provides for a multiple year RCP and why Rule 6.5.9 still today refers in detail to the establishment of 'X-factors'.

Under the current regulatory regime, the position prior to the advent of the NEM is wholly irrelevant. Even if the charges of the Electricity Trust of South Australia could be demonstrated to have provided net subsidies to customers or to have involved raising revenues for the owners in relation to the network assets that SA Power Networks still operate today, these became bygones when economic regulation commenced.

Again, there is no legislative basis to 'carry over' alleged windfall gains or losses from any previous regulatory periods when applying the rate of return objective on a forward looking basis for SA Power Networks' regulatory period that is now commencing.

In our view the AER has also misinterpreted Rule 6.5.2(k)(4) which provides for the impacts across regulatory periods of making a change. As the AER itself notes, the AEMC indicated that

> *'Its purpose is to allow consideration of transitional strategies so that any significant costs and practical difficulties in moving from one approach to another is taken into account.'*[492]

This provision does not provide a general license to bring to account costs over the life of the regulatory assets but rather focuses on the specific impacts of a movement from one regime to another – that is the costs arising from the change itself.

Finally, we note that the AER's approach implies such a long transition path that it would span two entire regulatory periods. It is not explained how the AER considers it has jurisdiction now to determine what will occur in the 2020 to 2025 period. Nor have the impacts of doing so been adequately considered. For instance, in the first year of the AER's second transitionary regulatory period (ie 2020) the trailing average will have only just obtained a 50% weighting and it is unclear whether that will be consistent with the requirements of Rule 6.5.2(k)(4) which requires regard to be

---

[490] That is compared with the main alternatives: rate of return regulation as traditionally used in North America and the other proposal of granting tax incentives for efficiency improvements that was also proposed at the time RPI-X regulation was invented.

[491] For example, see the interview of Stephen Littlechild by Jean-Michel Glachant and published by the European University Institute on October 7, 2013 and '*RPI-X, competition as a rivalrous discovery process, and customer engagement*', Littlechild, LSE, London, 31 March 2014.

[492] AEMC; *Rule Determination*, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012; 29 November 2012; page 85.

had to the 'incentives that the return on debt may provide in relation to capital expenditure over the *regulatory control period*, including as to the timing of any capital expenditure.'

Economically flawed

Of course there are good economic reasons for each of the issues discussed above. However, the AER's attempted implementation of the NPV principle is also itself flawed.[493]

As Dr Hird's report demonstrates, [494] there is no wind-fall gain to be had. In particular, when taking two past periods into account there were two different approaches in use:

- ESCoSA's 'rolling average' approach for the period 2005 to 2010; and
- The AER's 'on the day' approach for the period 2010 to 2015.

Dr Hird's assessment of the net effect over these 10 years is:

> *'While there was some over-compensation in the most recent regulatory period, it was offset by under-compensation in the preceding period. The average under-compensation is 0.053% and 0.059% for CEG and Chairmont cost of debt estimates over the previous two regulatory periods.'*[495]

It is notable that when the AER previously imposed a transition from ESCoSA's 'rolling average' method to its 'on the day' method, there was no NPV assessment undertaken and no compensation provided to SA Power Networks due to the net under-compensation that had accumulated under the 'rolling average' method.

How the AER should be approaching the task of establishing an allowed return on debt

Given there is no windfall gain or loss to be brought to account because it is both factually absent and legally impermissible, the only appropriate transition is one that approximately reflects the actual transactions that an electricity network business would enter into to move from a staggered long-term debt portfolio with base rate hedging to the long-term position in which the hedging component is progressively unwound.

Rule 6.5.2(k)(4) specifically provides for the recovery of these adjustment transactions.

(c) The credit rating

In our Original Proposal we explained why the AusNet (a majority government owned company) should not be included in the comparator set when determining the benchmark credit rating. An important feature of the comparators used for establishing the benchmark is that even before AusNet is removed from the AER's group, there are very few firms involved and this makes the median at any given time to be highly sensitive to small changes in the ratings decisions that are made even for a single entity amongst the group. It would obviously not be desirable for the regulatory allowance to fluctuate each time there was a single notch credit rating change for a single business.

There are two ways to address this. First, the benchmark should be set having regard to the median over a period that appropriately balances the need for contemporaneous data but long enough for a small short term credit ratings movements not to affect the benchmark. Five years is a suitable

---

[493] See CEG, *Critique of the AER's JGN draft decision on the cost of debt*, April 2015 at 4.3.3; pages 32-34.
[494] *CEG*; *Transition to the trailing average rate of return on debt. Assessment and calculations for SAPN*; June 2015; page 35.
[495] *Ibid.*

period. The second is to consider what credit rating a benchmark firm would have if it were subject to the methodology used by the credit ratings agencies.

Taking either of these approaches delivers a BBB credit rating, not a BBB+:

- the Victorian distribution businesses' current regulatory proposals[496] provide the median credit ratings over the five year period; and
- ActewAGL provided a report by CEG that applies the credit ratings agencies methodology to a hypothetical benchmark network business.[497]

At present, there is no quoted BBB+ curve so the AER accepts that the BBB curve should be used but only unless and until a BBB+ curve emerges – at which time the AER's Preliminary Determination would immediately adopt it for the in-period trailing average updates.

Even if the AER were correct that BBB+ were the correct and preferable credit rating (and we have explained why this is not so), the automatic update is unacceptable.

A reason the AER rejected the new issue premium in our Original Proposal was that other parts of the debt allowance decision overcompensates and the use of the BBB curve in place of a BBB+ curve is one of the two ways the AER asserts the allowance overcompensates. Therefore, before any move to use a BBB+ curve is taken, the new issue premium would need to be re-assessed.

(d) The choice of third party curves

Until recently the two available measures of the cost of debt were published by Bloomberg and the RBA. The former was publishing an estimate with a seven year tenor and the RBA was publishing one labelled a 10 year tenor but which in reality is an estimate for a marginally shorter term.

The AER tested these two options, scoring them on a range of considerations and ultimately reaching the conclusion that each performed better in some respects and not in others and on that basis the appropriate course would be to take a 50:50 average.

In SA Power Networks' Original Proposal, we accepted that approach while noting that we would keep this issue under review. We note that Jemena Electricity Networks has scrutinized some of the details of the AER method. While we consider that some valid weaknesses have probably been identified in the AER's approach to testing, the work presented by Jemena does not imply that either of the curves is unequivocally preferable in the present circumstances. We continue to consider that the AER's 50:50 average between the Bloomberg 7 year and RBA '10' year service is the most appropriate approach in the current times on the currently available information.

We recognise the AER's preference to apply a simple updating approach within the regulatory period when implementing the trailing average and we are not opposed to using a simple approach to sourcing the requisite data for the trailing average during the regulatory period.

Nevertheless, under the trailing average method, the Final Determination needs to foresee the possibility that the menu of available sources may alter over that period. If either the Bloomberg 7 year or RBA '10' year curve were to be discontinued, we consider that it is appropriate to use only the remaining curve to source the 'in period' trailing average statistics.

---

[496] For example, see AusNet; *Electricity Services Pty Limited Electricity Distribution Price Review 2016-20*; 30 April 2015; page 341.

[497] CEG; *Efficient debt financing costs, A report for ActewAGL*; 19 January 2015.

However, we do not agree with the proposition on page 3-204 of the AER's Preliminary Determination that Bloomberg's newly published 10 year figures should be used in place of the Bloomberg 7 year figure. It was Bloomberg's 7 year curve that the AER tested and not its 10 year curve. Noting the reservations we have about that testing (and in particular the concerns that Jemena has articulated), it was a 50:50 average involving Bloomberg's 7 year curve that we accepted would be unobjectionable.

The 10 year Bloomberg curve has not been tested by the AER and it should not be used.

CEG has commenced the process of scrutinising the appropriateness of using Bloomberg's 10 year curve and this has already revealed significant issues that suggest the curve is, on what has been unearthed so far, inappropriate for use.

In particular, there is a key difference between Bloomberg's 10 year curve and the RBA's 10 year curve that arises because of the bond selection criteria. Bloomberg uses a more restrictive bond sample than the RBA curve and this results in Bloomberg excluding all the available data with a term to maturity exceeding approximately 6.9 years. By contrast, the RBA uses a broader set of bonds and its data points do include longer term bonds.

Bloomberg's 10 year figures are, in fact, derived from extrapolating from its shorter term data. CEG asked Bloomberg what approach it used to derive the long end of its curve and it uses neither the 'SAPN method' nor the 'RBA method' of extrapolation. Rather, Bloomberg simply takes the shape of the long end of the curve for Commonwealth Government Securities and applies this to the corporate bond data.

> *'When queried by CEG on how Bloomberg could construct a BBB yield curve out beyond the available BBB bond data Bloomberg responded as follows:*
>
> > *On April 14, 2015, BVAL curve methodology has introduced enhancements to curve construction to enable curve derivation for tenors three months to 30 years. Curve derivation is now using the respective government benchmark as the underlying reference curve to enable curve construction over the full maturity spectrum, in the absence of data constituents. That's the reason why you noticed AUD Corporated BBB BVAL curve has suddenly been extended from 7 to 30 years starting from April 14, 2015.'*[498]

As CEG points out, that approach will (of course) underestimate the required returns for corporate debt because it wrongly assumes that lenders will be content with locking away funds in the hands of corporate borrowers for an additional three years on the same basis that lenders to the AAA rated Commonwealth Government would.

CEG concludes:

> *'Bloomberg appears to be basing its BBB BVAL yield curve shape on the shape of the government bond yield curve beyond around 5 years;*
>
> *As a matter of theory, this is likely to understate the increase in yields on BBB (as opposed to risk free) debt;*
>
> *This is borne out when the BBB BVAL curve is tested against the observed yields on longer dated BBB bonds issued by Australian corporates (both in the BVAL constituents and wider samples of bonds).'*[499]

[498] CEG; *Extrapolation of the Bloomberg curve to 10 years*; 19 June 2015; pages 5-6.
[499] Ibid; page 14.

The Bloomberg 10 year curve must not, therefore, be used. It has not been subjected to the AER's testing process nor the scrutiny of stakeholders and a preliminary scrutiny of the curve already reveals a significant flaw preventing it from being suitable when establishing a measure of debt that is commensurate with the costs of a benchmark efficient entity with a comparable level of risk.

Consequently, our Revised Proposal retains the use of a weighted average of Bloomberg's 7 year curve and the RBA '10' year curve.

(e) The extrapolation method

At present the two competing methods for deriving 10 year benchmarks from data of shorter tenors (the AER and SAPN methods) deliver very similar results. However, interest rates are volatile and it is important to adopt the best possible approach for the long term.

Dr Hird is of the view that, ideally, the best conceptual approach may vary depending on the prevailing economic circumstances.[500]

For our averaging period, Dr Hird states:

> *'Based on goodness of fit tests, we find that the RBA curve extrapolated according to the SAPN methodology best fits the broadest dataset over the averaging period. (However, we note that there is a small difference in levels between the RBA curve and the BVAL curve where both are extrapolated using the SAPN methodology.) Similarly, the SAPN extrapolation of the BVAL curve provides the best fit to the narrower RBA sample. The only exception is the RBA curve is a slightly better fit to the RBA sample when using the AER extrapolation.*
>
> *On this basis, I conclude that over the period from 9 February 2015 to 6 March 2015, the best method of extrapolation of the third party estimates to 10 year spread to swap is the SAPN method. When this is done, the BVAL and RBA estimates at 10 years are very similar. The average of these two estimates is 174.2 basis points in semi-annual terms, when added to the prevailing 10 year swap rate of 2.88%, corresponds to a 10 year cost of debt 4.62% in semi-annual terms, or an annualised yield of 4.67%.'*[501]

We would support that selection approach but for the considerations of seeking to provide as streamlined an approach as possible during the regulatory period. If a single method is to be chosen, the SAPN method is to be preferred. The AER method is very sensitive to the slope of the long end of the yield curve, which can, on occasion, even slope downwards if there are anomalies in the limited number of long dated bonds. On the other hand, the 'SAPN method' derives a slope over a longer portion of the yield curve and hence is less likely to deliver anomalous results. We would support the use of the 'SAPN method' throughout the regulatory period if a single method was required to be chosen for the duration of the whole regulatory period.

(f) New Issue Premium

In the AER's Preliminary Determination, the AER has acknowledged that:

> *'The effective cost of debt faced by an issuer is related to the yields at which its bonds are issued in the primary market. We estimate our return on debt*

[500] CEG; *Transition to the trailing average rate of return on debt. Assessment and calculations for SAPN*; June 2015; pages 12-23.
[501] Ibid; page 23.

> *allowance using third party curves. These provide an estimate of yields on bonds traded on the secondary market.'*[502]

It is our view that there is a systematic difference between these two measures (known as the New Issue Premium or NIP) and that, as a result, we tend to be undercompensated for our cost of debt under the AER's current approach.

The AER's Preliminary Determination rejects our proposed NIP. It provides a diverse range of reasoning including (a) conceptual criticisms; (b) comments concerning whether the NIP exists in the US and Europe as well as Australia; (c) criticisms of CEG's empirical work (including criticisms that, for example, CEG used a *more* comprehensive dataset than that used by the RBA or BVAL and did not disaggregate its data between the GFC and other periods); (d) claims that the AER's own estimation procedure for the cost of debt over-compensates us in certain respects (ie a claimed mismatch in the AER's preferred benchmark credit rating and tenor of debt compared with the data used to establish the benchmark cost) and that in the UK there are allegedly some empirical claims that its system over-compensates the firms within its jurisdiction and some claims of the same in Australia; and (e) limited evidence of other regulators according a new issue premium.

On the above basis the AER's Preliminary Determination rejects CEG's work, and our compensation adjustment for the NIP. We are disappointed that, having acknowledged that we raise debt in primary markets but the AER's estimated costs are drawn from secondary markets, the AER has not undertaken a conceptual or empirical analysis of its own. Rather it has limited its response to criticising CEG's efforts and raising a series of speculative possibilities, each of which would imply significant additional work before it could be concluded whether they were relevant or irrelevant. For example, without having undertaken any analytical tests as to whether the empirical analysis would be affected and if so in which direction, CEG is criticised for taking a broader (and in itself preferable) bond data than does the RBA or Bloomberg speculating that by some quirk this might affect the NIP estimate.[503]

We remain of the view that the CEG analysis is robust and more comprehensive than any of the other conceptual or empirical work available at this time. As such it is certainly a preferable basis for making a decision than merely to assume and impose a zero for the NIP.

However, we accept that in the time available to us between the AER's Preliminary Determination and the due date for lodgement of our revocation and substitution submission, it is unrealistic to address all the conceptual and empirical criticisms that have been levelled against this work. Consequently, without making any concessions concerning the existence of the NIP, we no longer press for the inclusion of a NIP adjustment at this time.

That said, we categorically reject the suggestions in the AER's Preliminary Determination NIP discussion that we are over-compensated in other aspects of the AER's Preliminary Determination such as using published BBB debt curves instead of BBB+ curves or 10 year tenor. For the reasons that are well set out in our previous submissions and other parts of this proposal, the appropriate benchmark for the debt allowance is a BBB curve of 10 years' tenor.

[502] AER Preliminary Determination Attachment 3 at [3-470].
[503] Ibid; at [3-480].

(g) Summary

In summary, our debt allowance should be established using:

- a BBB credit rating;
- the trailing average method;
- a 50:50 average of data sourced from Bloomberg 7 year curve and the RBA's '10 year' curve; and
- the curves should be extrapolated using the 'SAPN method' in our 'place holder' averaging period.

On that basis, Dr Hird states that the allowance in our 'place holder' averaging period in February 2015 would be 5.29%.[504]

For the reasons set out above, even when data is available from Bloomberg's new 10 year curve it should not be used for updating the allowed rate of return during the regulatory period.

13.10 Inflation

13.10.1 SA Power Networks' Original Proposal

The Rate of Return Guideline does not address the issue of what is the best estimate for inflation and instead leaves it to be decided as part of the Final Determination:

> *'As discussed with stakeholders, the final guideline does not cover our position on transactions costs or forecast inflation. These issues will need to be considered in upcoming determinations.'*[505]

When we lodged our Original Proposal, it was not apparent to us that the methodology the AER has been using since 2008 was flawed (as we discuss below) and consequently we adopted it. That method involves using the RBA's forecasts of inflation (where available) and the RBA's targets for inflation in the 'out years' of the regulatory proposal for which the RBA does not publish forecasts.

13.10.2 AER's Preliminary Determination

In the Preliminary Determination the AER has continued to use the RBA's forecasts of inflation (where available) and the RBA's targets for inflation in the 'out years' for which the RBA does not publish forecasts.

13.10.3 SA Power Networks' response to AER Preliminary Determination

Evidence has now come to light from recently available analysis by Dr Hird that the AER's approach to estimating inflation results in significant under-compensation in the prevailing economic conditions (CEG, Measuring the expected inflation rate, June 2105).

There are two principal issues:

- Over what period should the inflation rate estimate be generated; and
- From what source should it be estimated.

[504] CEG; *Transition to the trailing average rate of return on debt. Assessment and calculations for SAPN*; June 2015; pages 12-23.
[505] Explanatory Statement; page 28.

CEG has prepared a report on these issues and the key points are summarised below.

(a) Period over which the inflation rate should be estimated

As CEG states, to obtain a suitable inflation estimate it is necessary to understand how the estimate is used in the regulatory structure. The PTRM effectively takes the following steps:[506]

i. Takes a nominal input for the cost of debt and equity;

ii. Deducts forecast inflation (another input into the PTRM) to arrive at a real return which is then embedded in the real regulated revenue path;

iii. Provides nominal compensation that is equal to:

a. The real return derived in step ii); plus

b. The inflation that will occur over the regulatory control period (this is compensated primarily in the RAB roll forward model used to set the opening RAB at the beginning of the next regulatory period but also in the form of price escalation for inflation during the regulatory period).

Then:

> *'The real revenue path in step ii) is the final output of the PTRM and is expressed in terms of a real 'X'% increase or decrease plus actual inflation that will accrue (but is not yet known) over the regulatory period. This gives rise to the familiar CPI±X% expression of the revenue/price path.'*[507]

CEG shows algebraically that:

> *'Given that the AER uses a 10 year forecast of inflation in the PTRM, then whenever 5 and 10 year forecasts are different, the expected nominal compensation will not match the estimated nominal costs inputted into the PTRM.'*[508]

However, CEG states that:

> *'For the reasons described below this is:*
>
> - *entirely appropriate where the relevant cost is a fixed real cost, such that the corresponding nominal value varies with inflation (as is the case for the cost of equity); and*
> - *inappropriate where the relevant cost is a fixed nominal cost, such that the corresponding real value varies with inflation (as is the case for the cost of debt).'*[509]

In essence for equity:

[506] CEG; *Measuring expected inflation for the PTRM*; June 2015; paragraph [122]; page 41.
[507] CEG; *Measuring expected inflation for the PTRM*; June 2015; paragraph [123]; page 41.
[508] CEG; *Measuring expected inflation for the PTRM*; June 2015; paragraph [126]; pages 41-42.
[509] CEG; *Measuring expected inflation for the PTRM*; June 2015; paragraph [126]; page 42.

'The AER arrives at a real cost of equity by building up a cost of equity based on a 10 year CGS yield as the proxy for the CAPM risk free rate.

This means that 10 year inflation expectations are embedded in the AER's nominal cost of equity. It follows that the real cost of equity demanded by investors must be estimated by removing expected inflation with ***the same*** *10 year horizon.'*[510]

However, for debt:

'The same is not true when it comes to the cost of debt because, unlike the cost of equity, the cost of debt is a nominal contract with lenders.[511] *Moreover, the cost of debt input into the PTRM is an estimate of the nominal payments made in each year of the regulatory period (while the nominal cost of equity is an estimate at a horizon beyond the regulatory period).*[512]

Consequently, the nominal cost of debt must be converted into a real cost of debt within the PTRM using an inflation forecast that is expected to be the same as the actual inflation that will 'reinflate' real compensation over the regulatory period (under the CPI±X revenue path) and, most crucially, in the RAB roll-forward model applied at the beginning of the next regulatory period.'[513]

In other words a 60:40 weighted average of the relevant 5 and 10 year measures of inflation is what should be estimated.

An additional issue arises in the highly unusual circumstances in which the Final Determination is a revocation and substitution such that part of the relevant period will already have elapsed:

'[I]n the special case of SAPN, the AER will be making its final decision in 2015/16 to apply retrospectively to the regulatory period starting in July 2015. Therefore, at least some of the ABS published rates will actually be available to inform the AER's best estimate of inflation that will be used in the RAB roll forward model.[514]

…

To the extent that the AER final decision is made after these dates then regard should be had to the actual inflation that has already occurred and been measured by the ABS. This means that the five year inflation forecast that is paired with the cost of debt will need to be an average of actual inflation already measured and prospective inflation not yet measured.'[515]

(b) Source of the inflation estimate

The current method that the AER uses to estimate inflation is partly based on RBA forecasts but the forecasts generally only extend out for one or two years. For the rest of the years the RBA's target inflation level is used as if it is an estimate of the inflation that is likely to occur. That approach would

[510] CEG: *Measuring risk free rates and expected inflation*; April 2015; paragraphs [66-67]; page 21.
[511] The nominal cost of debt is fixed in nominal (not real) terms and is estimated specific to each year of the regulatory control period (not beyond).
[512] CEG: *Measuring risk free rates and expected inflation*; April 2015; paragraph [74]; page 22.
[513] CEG: *Measuring risk free rates and expected inflation*; April 2015; paragraph [75]; page 23.
[514] CEG: *Measuring risk free rates and expected inflation*; April 2015; paragraph [85]; page 25.
[515] CEG: *Measuring risk free rates and expected inflation*; April 2015; paragraph [86]; page 25.

be appropriate if the RBA's use of its monetary policy instruments were effective in, on average, meeting the targets.

However, there is extensive evidence that the RBA and its fellow central banks internationally are struggling with the available monetary policy instruments to bring about the desired movements towards their targets in the face of strong deflationary market forces. As CEG notes that the RBA's senior staff and the Board itself have acknowledged this publicly:

> *'Overall, looking at this experience, I find it difficult to escape the conclusion that changes in interest rates are not affecting decisions about spending and saving in the way they might once have done.'*[516]
>
> *'The Board is also very conscious of the possibility that monetary policy's power to summon up additional growth in demand could, at these levels of interest rates, be less than it was in the past. A decade ago, when there was, it seems, an underlying latent desire among households to borrow and spend, it was perhaps easier for a reduction in interest rates to spark additional demand in the economy. Today, such a channel may be less effective. Nonetheless we do not think that monetary policy has reached the point where it has no ability at all to give additional support to demand. Our judgement is that it still has some ability to assist the transition the economy is making, and we regarded it as appropriate to provide that support.'*[517]

More broadly, CEG notes that it is not only RBA who is concerned about the impotence of its traditional instruments in the current circumstances:

- *'global inflation rates have been persistently below target, with instances of deflation in the US, Japan, the UK and the Eurozone;*
- *the ability of monetary policy to provide economic stimulus is limited, given the proximity of official interest rates to the 'zero lower bound', coupled with the fact that, at current low interest rates, further rate reductions are of uncertain value in terms of providing economic stimulus; and*
- *the IMF's April 2015 World Economic Outlook publication specifically mentions Australia as being at risk of falling into a low inflation trap.'*[518]

Meanwhile market participants form views about the level of inflation. As CEG states:[519]

> *'In this context, it is reasonable to expect that investors perceive an asymmetry in the probability that inflation will be above/below the RBA's target, at least in the medium term.*
>
> *This means that, even if the 'most likely' estimate is for expected inflation to average 2.5% in the medium to long term, this is not the mean (probability weighted) estimate. That is, there is more downside than upside risk to inflation.*

[516] RBA Deputy Governor Lowe; *Speech to the Goldman Sachs Annual Global Macro Economic Conference, Sydney*; 5 March 2015.
[517] RBA Governor Stevens; *Opening Statement to House of Representatives Standing Committee on Economics, Sydney*; 13 February 2015.
[518] CEG: *Measuring risk free rates and expected inflation*; April 2015; paragraph [13]; page 3.
[519] *Ibid*.

Indeed, this is precisely what market-based estimates of expected inflation are predicting – as I discuss in the subsequent sections.'[520]

Importantly, this is not an issue of whether the RBA is right or the market participants are wrong. Rather all parties, the RBA included, are concerned that the tools available to central banks are such that the actual inflation is not expected to conform to the mid-point of the target range agreed between the Governor of the Reserve Bank and the Treasurer of between 2% and 3% on average in the medium term.[521]

There are alternatives. The markets themselves provide data that can be used to forecast inflation but the use of market based sources of estimated inflation for energy regulatory purposes was discontinued in 2008 due to distortions that had arisen in the specific circumstances that applied at that time.

Up until 2008, the AER had been using the 'break-even' method for preparing inflation forecasts, which meant that it was comparing the yields on nominal Commonwealth Government Securities (CGS) with the yields on Treasury indexed bonds, and applying a Fisher equation transformation. However, in its final decision for SP AusNet transmission, in January 2008, the AER chose to adopt a different method, which was ostensibly based on forecasts of inflation from independent providers. The AER noted in the determination that:[522]

> *'In the absence of a robust market based estimate, the AER agrees with SP AusNet's emphasis on independent forecasts in its Revised Proposal. However, the AER considers that more regard should be given to inflation forecasts from the RBA than those available from the various forecasters cited by SP AusNet and NERA, as the RBA is responsible for monetary policy in Australia, and its control of official interest rates and commentary has a significant impact on both outturn inflation and inflation expectations. In its latest Statement on Monetary Policy the RBA forecast inflation to be 3% in the 12 months to December 2008, and 2.75-3% in the 12 months to December 2009. The AER considers the RBA's forecasts represent the best estimates of forecast inflation for these two years. The RBA does not release inflation forecasts beyond a two year period.'*

And:

> *'In the absence of a reliable market based estimate, and acknowledging the difficulty of forecasting inflation beyond the short term, the AER considers 2.5% to be a reasonable estimate of inflation beyond the RBA's forecast period. Averaging the RBA's forecasts for 2008 and 2009 with 2.5% for the remaining 8 years produces a 10 year inflation forecast of 2.59%.....'*

In almost every regulatory decision since 2008, the AER has adopted a projection for inflation which is at or close to 2.5 per cent.

The AER approach to preparing inflation forecasts makes use of the following steps:[523]

- Draw upon the near term projections for inflation from the latest available version of the RBA Statement on Monetary Policy. Use the results from the Statement for underlying inflation to produce inflation forecasts for the next two years.

---

[520] CEG: *Measuring risk free rates and expected inflation*; April 2015; paragraph [33]; page 10.
[521] The statement on the conduct of monetary policy, the Treasurer and the Governor of the Reserve Bank, 2013.
[522] AER (2008); *Final Decision, SP AusNet transmission determination, 2008-09 to 2013-14*; January 2008; pages 103-104.
[523] See, for instance: AER; *Final Distribution Determination, Aurora Energy Pty Ltd, 2012–13 to 2016–17*; April 2012.

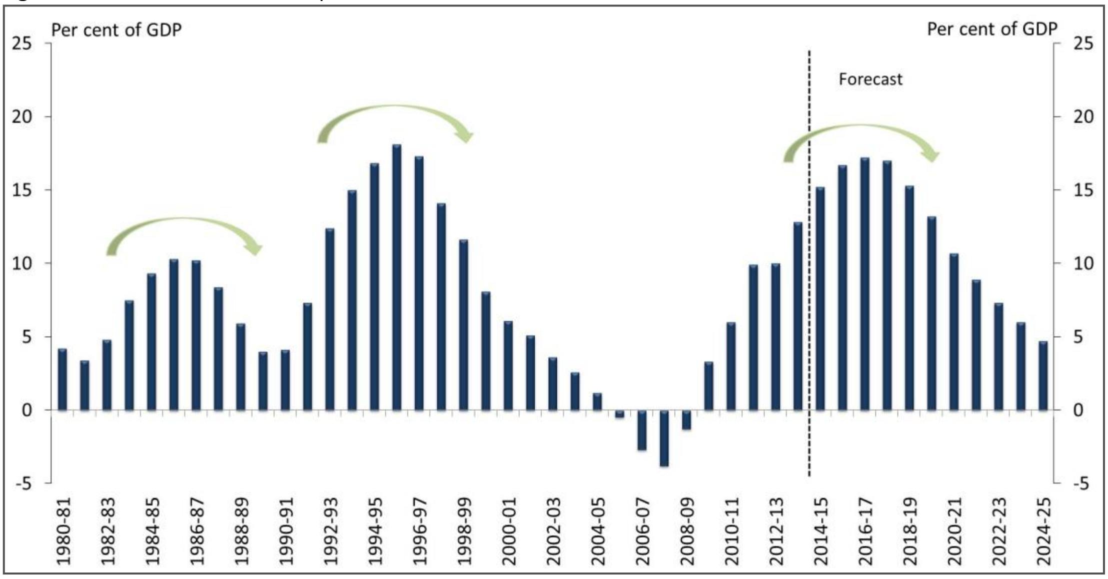
- For year three to year 10, insert a value of 2.5 per cent in the corresponding cells of the AER's inflation forecasting template. The value of 2.5 per cent is the mid-point of the range for inflation targeting that is used by the RBA.
- The values of the inflation forecasts for the individual years are transformed into an index, with a value of 100 being assigned to the year proceeding the current year.
- A geometric mean is then fitted to the entire series, making use of the ultimate value of the index in the final year out of ten years (or 11 years, if the immediately preceding year is also counted).

It is now clear that the above method is not producing an optimal and reliable forecast for inflation at the present time and recent developments in financial markets suggest that a re-appraisal of the AER's approach to developing inflation forecasts is now warranted.

In principle, the most direct and accurate way to set a rate of return allowance that is commensurate with the prevailing costs of a benchmark entity is to use market prices that are either directly observed from financial markets, or else can be inferred from financial markets. Prior to 2008, the inflation figure used to adjust the regulatory asset base (and, thereby, indirectly to apply a real rate of return in place of a nominal rate of return) was indeed drawn from financial markets. The Fisher equation was used to compare the yields on Treasury fixed rate bonds with the yields on Treasury indexed bonds, and to thereby infer an inflation rate which was consistent with market expectations.

However, between 1995 and 2008, there was a marked reduction in the volume of all CGS on issue. There are some investor classes for which adequate substitutes for CGS were not available, and there was a belief in the market that observed yields on CGS might have been affected by that scarcity. However, since 2008, the volumes of CGS on issue have increased significantly, both in dollar terms and as a proportion of GDP:[524] Figure 3: Australia's net debt position and Figure 4: Australian Government Bonds on issue provide a perspective on Australian Commonwealth Government debt, with the figures, and, indeed, the charts, having been sourced from the Australian Office of Financial Management.

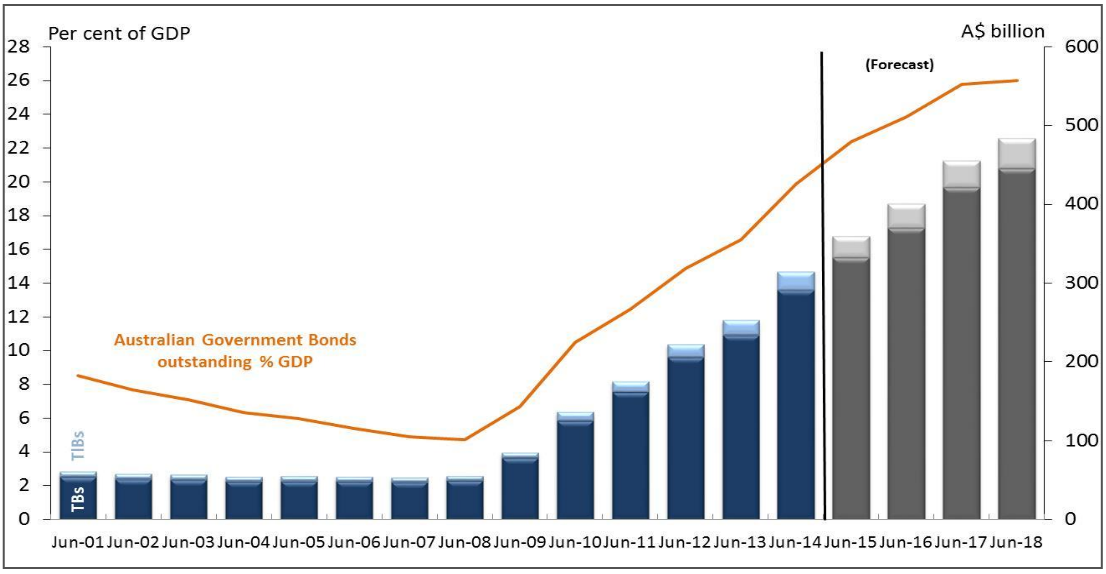
Figure 13.3: Australia's net debt position



[524] Australian Office of Financial Management*; Investor Handout*; December 2014; page 14.

The value of indexed CGS on issue has increased from approximately $6 billion in 2009 to $18 billion in 2013.[525] Furthermore, the outstanding stock of CGS is not expected to diminish at all over the regulatory period.[526]

Figure 13.4: Australian Government Bonds on issue



Consequently, there is no longer a presumption in favour of the use of third party forecasts of inflation in place of the implied inflation measure that is provided by financial markets.

CEG agrees and consequently our Revised Proposal adopts CEG's recommendation that:

> *'Adopting breakeven inflation, unlike adopting the midpoint of the RBA's inflation target, can be viewed as the probability weighted forecast of inflation in all possible circumstances that market participants perceive.'*[527]

We also note that CEG has used inflation swap trading data to check the usefulness of the estimate drawn from the break-even method and that check corroborates the use of the break-even method.

(c) The inflation estimate

As set out in the CEG report, during our 'place holder' or illustrative averaging period of 9 February to 6 March 2015, the estimated inflation rate using the 60:40 weighted average of 5 and 10 year inflation using the break-even method delivers a forecast of 2.06%.[528] This is the figure that we have used for our Revised Proposal rather than the method used in the AER's Preliminary Determination which is approximately half a per cent higher.

This figure should be updated consistent with the CEG report at the time of the Final Determination.

---

[525] Ibid.
[526] Ibid; page 16.
[527] CEG: *Measuring risk free rates and expected inflation*; April 2015; paragraph [36]; page 10.
[528] CEG: *Measuring risk free rates and expected inflation*; April 2015; table 2; page 19.

13.11 Revised Proposal

As part of our revocation and substitution submission, we are submitting a Revised Proposal. For the reasons set out above, the Revised Proposal:

- maintains the position in our Original Proposal concerning the allowed rate of return on equity (which delivers a return of 9.83%) and gamma (which should be 0.25);
- includes the 'hybrid' transition also referred to as Option 4 in the AER's Preliminary Determination (which delivers a return of 5.29% using the 'place holder' averaging period); and
- reforms the way in which the inflation rate is determined by using actual recorded inflation for that part of the regulatory period that has already elapsed and otherwise market based measures instead of the forecasts and mid-point targets of the Reserve Bank of Australia.

13.12 Materially Preferable NEO Decision

It is essential that electricity network businesses are permitted to earn a fair market return at all times in order to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity. If a fair return is not permitted, the business cannot attract the equity investments needed to maintain assets and replace them when required.

In the short term, no discernible difference in service may be observed because investment decisions are made for the long term. However, in the short term incentives arise to delay replacement investments or efficient capital augmentations and instead to continue to rely on the existing assets beyond when they should be most efficiently replaced.

In the longer term, if regulatory determinations were to persist with providing inadequate returns for more than a single five year regulatory period (or even sooner if investors take the current determination process as indicative of the AER's long run approach) the business would most likely end up being under-capitalised. Financial failures are, of course, a very low probability but high risk event for consumers and other end-users.

Equally, a significantly below market return during the current five year regulatory period would negatively affect investors' perception of the sovereign risk of investing. This would raise the long term revenue expectations when investing to the detriment of consumers across the NEM.

For the reasons explained in this Revised Proposal, the AER's Preliminary Determination did not provide a fair rate of return for the capital invested. The below market equity allowance arises from the use of a systematically downwardly biased SL-CAPM, exacerbated by its 1:1 relationship with base interest rates (which are at historic lows), whilst constraining the contribution made by all the other available models. All those models deliver higher returns on equity.

Additionally, the AER has failed to provide an adequate risk adjusted return in the face of the rapid uptake of disruptive technologies.

The AER's Preliminary Determination debt allowance is also inadequate particularly because of the inappropriate transitional arrangements accompanying the introduction of the trailing average. The short-fall in the debt allowance is borne by equity holders because debt holders take a fixed market return regardless of the below-market regulatory allowance.

Each of the above flaws in the AER's Preliminary Determination (ie the use of the foundation model, the failure to take adequate account of other models, inadequate returns in the face of low base interest rates, a failure to compensate for the risk of disruptive technologies and the inadequate debt allowance) taken separately or combined, put unacceptable stress on our ability to raise equity and undermine our ability to invest for the long term. Unless these flaws are rectified, end customers of electricity will ultimately bare the ill effects.

Further, we are concerned that the approach in the AER's Preliminary Determination leads to excess volatility in returns which will send confusing pricing signals to end consumers. As we have explained, the AER's SL-CAPM is delivering unprecedented depressed returns due to the link with very low base interest rates. The transition path to the ten year trailing average also initially locks in unprecedented low interest rates by applying a 100% weighting to the 'on the day' method in the first regulatory year at a time when interest rates are at a record low and only very slowly reducing that proportion.

This approach to setting the equity and debt allowances will result in very substantial increases as the interest rate cycle turns. When interest rates are at above average levels, this will flow through to equity and debt allowances, which could (but for the low beta bias of the SL-CAPM) tend to result in permitted revenues rocketing upwards and over-stimulating network investments.

As Gray and Hall's report on gamma explains, the level of gamma significantly affects the returns that investors receive and it is essential that electricity network businesses are permitted to earn a fair market return at all times in order to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity. For the reasons explained in our proposal, the AER's Preliminary Determination of a gamma of 0.4 will not deliver a fair rate of return for the capital invested.

Page left blank intentionally

14. Depreciation

14.1 Rule requirements

Clause 6.5.5 of the National Electricity Rules provides as follows:

'*(a)* The depreciation for each regulatory year:

(1) must be calculated on the value of the assets as included in the regulatory asset base, as at the beginning of that regulatory year, for the relevant distribution system; and

(2) must be calculated:

(i) providing such depreciation schedules conform with the requirements set out in paragraph (b), using the depreciation schedules for each asset or category of assets that are nominated in the relevant Distribution Network Service Provider's building block proposal; or

(ii) to the extent the depreciation schedules nominated in the Distribution Network Service Provider's building block proposal do not so conform, using the depreciation schedules determined for that purpose by the AER.

(b) The depreciation schedules referred to in paragraph (a) must conform to the following requirements:

(1) 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;

(2) the sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category of assets (such real value being calculated as at the time the value of that asset or category of assets was first included in the regulatory asset base for the relevant distribution system) must be equivalent to the value at which that asset or category of assets was first included in the regulatory asset base for the relevant distribution system;

(3) the economic life of the relevant assets and the depreciation methods and rates underpinning the calculation of depreciation for a given regulatory control period must be consistent with those determined for the same assets on a prospective basis in the distribution determination for that period.'

The AER is not free to simply determine its own depreciation schedules. If the depreciation schedules proposed by a DNSP satisfy the requirements in clause 6.5.5(b), they must be used in calculating depreciation allowances, even if the AER has a preferred method for determining depreciation schedules.

The AER has assessed SA Power Networks' proposed depreciation schedules by comparing them with schedules produced using the AER's preferred method. SA Power Networks understands that the AER adopts this approach as it considers that depreciation schedules produced using its own method would satisfy the requirements of clause 6.5.5(b).

This approach may be seen as complying with the requirements of clause 6.5.5, *provided* that the AER does not reject a DNSP's proposed depreciation schedules simply because they differ from those produced by the AER. It is still necessary for the AER to consider whether the schedules proposed by the DNSP satisfy the requirements of clause 6.5.5. If they do, the proposed schedules must be accepted, even if they differ from the AER's preferred approach.

14.2 SA Power Networks' Original Proposal

The depreciation allowances proposed by SA Power Networks in its Original Proposal were as shown in Table 14.1.

Table 14.1: Original Proposal regulatory depreciation for the 2015-20 RCP (nominal, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Straight-line depreciation	229.9	267.8	304.9	341.3	373.5	1,517.6
less inflation indexation on opening RAB	(97.6)	(106.5)	(116.3)	(125.8)	(135.2)	(581.5)
Regulatory depreciation	**132.3**	**161.3**	**188.6**	**215.5**	**238.3**	**936.0**

SA Power Networks calculated its depreciation allowances by applying straight line depreciation to each proposed asset class, using the AER's Post Tax Revenue Model (**PTRM**). New assets were depreciated according to standard lives for each asset class. Existing assets were depreciated over their remaining asset lives. Opening asset values at 1 July 2015 have been calculated applying the AER's Roll Forward Model (**RFM**). Except for a new asset class (Vehicle – 10 years) the standard lives for assets in each class were those applying in the 2010-15 RCP.

The remaining lives of existing assets at 1 July 2015 were determined by calculating the average depreciation of assets in each class, using a simple average approach. This was the same approach used by SA Power Networks (then ETSA Utilities) and approved by the AER for the 2010-15 RCP, and is discussed in further detail below.

For the purposes of forecasting the cost of corporate income tax pursuant to clause 6.5.3 of the Rules, SA Power Networks calculated tax depreciation in accordance with tax law. Tax depreciation is calculated on a straight line basis, using applicable tax depreciation rates. Chapter 15 provides further details on the allowance for corporate income tax.

14.3 AER's Preliminary Determination

The AER did not accept SA Power Networks' proposed depreciation allowance of $936.0 (nominal, $ million) for the 2015-20 RCP, instead determining a depreciation allowance of $533.7 (nominal, $ million).

The chief point of departure from SA Power Networks' proposal was the AER's rejection of the averaging method used by SA Power Networks to determine remaining lives in each asset class. The

AER rejected SA Power Networks' use of a 'simple average' method, and substituted depreciation allowances calculated using a weighted average remaining life (**WARL**) approach.

The AER did not accept SA Power Networks' proposed depreciation allowances, instead substituting the allowances shown in Table 14.2 below in accordance with clause 6.12.1(8) of the Rules.

Table 14.2: Preliminary Determination regulatory depreciation for the 2015-20 RCP (nominal, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Straight-line depreciation	176.4	199.7	223.7	246.1	242.0	1,087.9
less inflation indexation on opening RAB	(97.6)	(104.0)	(110.8)	(117.6)	(124.1)	(554.2)
Regulatory depreciation	**78.8**	**95.6**	**112.8**	**128.5**	**117.9**	**533.7**

In making this decision, the AER accepted SA Power Networks' proposed asset classes, its use of straight line depreciation, and the majority of its proposed asset lives. The AER did not accept the proposed standard asset life of the 'Light vehicles' asset class. The AER considered the standard asset life for this asset class should be five years consistent with that approved for the 2010-15 RCP, compared to the four years proposed.

However, the AER did not accept SA Power Networks' proposed method for determining average remaining asset lives as at 1 July 2015. This was the major point of departure between SA Power Networks and the AER, and is the focus of this Revised Proposal.

The AER's reasons are set out in Attachment 5 to its Preliminary Determination. In these reasons, the AER found that:

- SA Power Networks' approach 'consistently underestimates the remaining asset lives'; [529] and
- remaining asset lives determined using the AER's WARL approach *'better reflect the nature of the assets over their economic lives*'. [530]

The AER explained why it considered the WARL approach to be the better method for calculating the remaining lives of the assets in each asset class.

The AER has stated the following:

> *'The most accurate way of estimating remaining asset lives is to track every asset individually. That is, record each asset added to the RAB and track its value over time.'* [531]

However, the AER identifies several drawbacks with this approach, namely:

[529] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015,page 5-11

[530] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015,page 5-17

[531] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015,page 5-12

- because of the large number of assets to be added to the RAB over time, this approach places significant administrative costs on the business and regulator; and

not tracking assets individually may reduce volatility in revenues. [532]

To reduce administrative costs, assets may be combined into classes, with an average remaining life assigned to the assets in each class. This average remaining life is re-calculated at each reset.

The AER assessed two methods by which average remaining lives could be calculated:

- a WARL approach (the approach favoured by the AER); and
- an average depreciation approach (the approached originally proposed by SA Power Networks).

Importantly, the AER states (at pages 5-12 to 5-13):

> *'The remaining asset lives calculated by both the WARL and average depreciation approaches are not perfect compared with the approach of tracking assets individually. Some information is lost when assets are combined into a single asset class, and when new assets are added to that asset class. For this reason, we focus on the materiality of calculation distortions relative to the 'true' remaining asset lives (that is, remaining asset lives if assets were not aggregated into asset classes and they were not recalculated at each reset).*
>
> *We prefer the WARL approach to the average depreciation approach because we consider it results in remaining asset lives that better reflect the economic life of the combined assets. It also results in depreciation schedules for the asset classes that reflect the nature of the assets over their economic lives.'*

The AER's analysis of the two methods leads it to conclude that the WARL approach better deals with the consequences of combining old and new assets in a single class, producing a more balanced outcome in the long run. In comparison, SA Power Networks' averaging approach tracks closely to asset values for 10 years, but thereafter depreciates the remaining asset lives too rapidly.[533]

14.4 SA Power Networks’ response to AER Preliminary Determination

SA Power Networks accepts the AER’s preliminary decision with respect to the standard lives and has incorporated a standard life of five years for the 'Light vehicles' asset class.

SA Power Networks does not share the AER's views as to the relative merits of the two averaging methods, or the conclusion that the AER's analysis justifies the rejection of SA Power Networks' proposed depreciation schedules on a proper application of clause 6.5.5 of the Rules.

However, rather than debating the AER's analysis, SA Power Networks has proposed a revised approach to determining remaining assets lives which better reflects the principles outlined by the AER in its Preliminary Determination.

SA Power Networks shares the AER's view that:

a) the most accurate way of estimating remaining asset lives would be to track every asset individually; and

---

[532] Ibid. (also see footnote 23)
[533] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, pages 5-16 to 5-17.

b) an approach which produces average remaining lives (either WARL or a simple average) is imperfect compared with the more accurate approach of tracking assets individually.

Combining old and new assets in the same class must, by definition, result in an average life that differs from the actual remaining lives of the individual assets that constitute the class, irrespective of the averaging method used (ie it results in information being 'lost', thereby creating distortions relative to actual remaining asset lives).[534]

It follows that an approach which does not combine old and new assets in the same class (thereby avoiding the need to average those lives) must, by definition, produce depreciation schedules that reflect more accurately the remaining lives of the individual assets in each class.

SA Power Networks' revised approach reflects this principle and in doing so accepts the AER view as reflected in the preliminary decision that the most accurate way of estimating depreciation is by way of a detailed asset register approach.

The report, prepared by Houston Kemp (and set out in Attachment N.1.), identifies and compares four methodologies that might be used, in the present context, for determining remaining lives in each asset class. These are described by Houston Kemp as:

- the 'baseline' approach;
- the 'WARL' approach (favoured by the AER);
- the 'average depreciation' approach (originally proposed by SA Power Networks); and
- the 'WARL of capex only' approach.

Importantly, Houston Kemp recognises, at page 12 of its report that for any single asset class:

> *'a single remaining asset life (which would produce a straight line reduction in asset values) cannot perfectly match the economic lives of a group of assets with disparate economic lives. In other words, no single remaining asset life can correctly depreciate all of SA Power Networks' 'Distribution Lines' assets that is composed of:*
>
> - *new investments that occurred during the 2010-15 period, which have a remaining life at 1 July 2015 of close to 55 years; and*
> - *assets in existence at the start of the 2010-15 regulatory period that have a remaining life at 1 July 2015 of 16.1 years.'*

Houston Kemp go on to examine the extent to which each of the four methodologies it identifies produce depreciation profiles that align with remaining lives of the individual assets in each class, concluding (at page 15):

> *'Our analysis clearly shows that a single remaining asset life cannot generate a depreciation allowance that accurately reflects a group of assets with disparate economic lives. Consequently, depreciation schedules that are generated by combining existing assets (with short remaining lives) and new capital expenditure will result in substantial intergenerational equity issues.*
>
> *Consequently, we recommend that SA Power Networks adopts either:*

---

[534] AER, *Preliminary Decision: SA Power Networks determination 2015-16 to 2019-20*, April 2015, pages 5-12 to 5-13.

- *the baseline approach, which results in the depreciation for all post 1 July 2010 capital expenditure being precisely calculated, while assets in existence at 1 July 2010 are depreciated over the remaining asset lives determined in SA Power Networks 2010 final decision; or*
- *the WARL of capex approach, which separately calculates for each asset category the economic lives of existing assets and new capex over each regulatory period thereby avoiding the distortions associated with combining assets with disparate economic lives.'*

This finding is consistent with the AER's own Preliminary Determination. The averaging method used by the AER is not perfect, since it results in information being 'lost' when old and new assets are combined into a single asset class, and creates an inter-generational issue.

Accordingly, SA Power Networks has adopted the 'baseline' approach to determining remaining asset lives for the purpose of this Revised Proposal, for both the RAB and tax asset base. Under this approach:

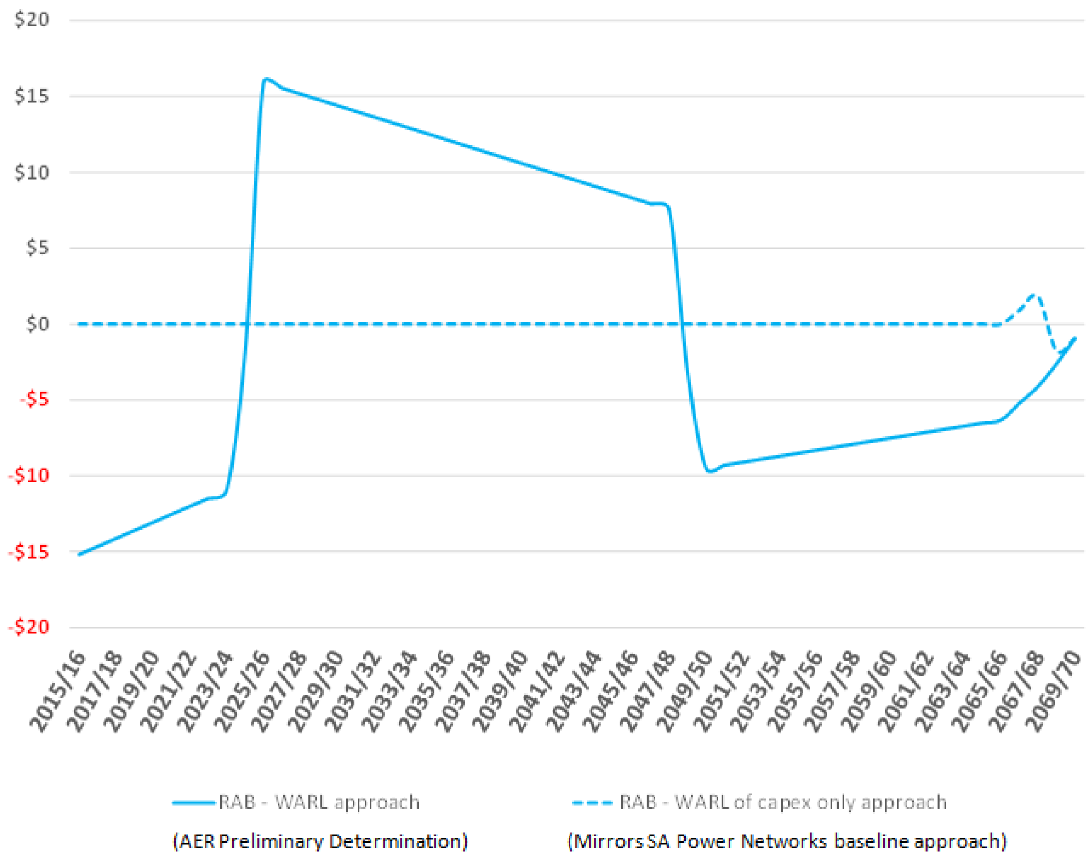
- assets in existence as at 1 July 2010 are depreciated by asset class, using straight line depreciation over the 2010-15 RCP; and
- capital expenditure in each regulatory year of the 2010-15 RCP is grouped together by asset type and then separately depreciated over their standard lives. Note this provides the *same* depreciation as if each asset were individually depreciated as individual assets are depreciated for the first time in the year following the year of addition.

Under this approach, there is no grouping of pre and post-2010 assets in the same asset class. The distortion of remaining asset lives that results from combining pre and post-2010 assets in the same class is avoided, and the resulting depreciation schedules align more closely with the actual remaining lives of individual assets than those produced using either:

- the simple average approach originally proposed by SA Power Networks; or
- the WARL approach favoured by the AER.

SA Power Networks' baseline approach outcome closely mirrors that of the WARL of capex only approach. Accordingly, our baseline approach removes the inter-generational issue created by the AER's Preliminary Determination (refer Figure 14.1, as it relates to low voltage assets by way of example).

Figure 14.1: Return of capital outcomes (low voltage system asset class) – SA Power Networks baseline approach vs WARL of capex only approach and AER's WARL approach (June 2015, $ million)



Source: SA Power Networks 2015

The calculations of remaining lives for both the RAB and tax asset base under this approach are contained in a separate spreadsheet model, which is provided at Attachment N.2. This model includes documentation of the sources of data and model workings. The model has been reviewed for accuracy by KPMG. This model will be maintained and rolled forward for each future RCP, so that the depreciation of the assets as at 1 July 2010 and in each regulatory year after 2010 are separately depreciated over their standard lives.

The baseline approach has a further advantage (when compared to either of the averaging methods) in that it does not artificially prolong the remaining life of old assets by combining them with newer assets to produce an average remaining life. SA Power Networks is concerned that this attribute of the AER's averaging methodology creates a risk that the return of capital will be delayed, and that SA Power Network's RAB will not reduce as quickly as it should. It is noteworthy that the AER itself, at page 3-376 of its Preliminary Determination, recognises that *accelerated* depreciation may be appropriate as a means of responding to disruptive technologies in the Australian energy sector. A method which *prolongs* the depreciation of the RAB produces intergenerational equity issues and contradicts an approach that could, according to the AER, be appropriate if disruptive technologies become a factor in the energy sector.

Houston Kemp also propose an alternate methodology to the baseline approach (the WARL of capex approach) which separately calculates for each asset category the economic lives of existing assets and new capital expenditure over each RCP, thereby avoiding the distortions associated with combining assets with disparate economic lives. The advantage of this methodology is that it combines additions over the 2010-15 RCP for an individual asset category into a single sub asset line reducing administrative costs. This approach was adopted by TransGrid in its revenue proposal for its 2014-19 RCP. In its revenue proposal, TransGrid created separate asset classes for different regulatory periods for certain types of assets.[535] This approach was approved by the AER under clause 6A.6.3 of the Rules.[536] We note that this approach provides a depreciation allowance consistent with that determined applying the baseline depreciation methodology submitted in our Revised Proposal, as shown in the Houston Kemp expert report.

Clause 6.5.5(a) of the NER requires depreciation to be calculated using the depreciation schedules nominated by SA Power Networks, provided those schedules conform with the requirements in clause 6.5.5(b) of the NER. The AER assessed those proposed schedules by comparing them with the depreciation schedules produced using the AER's preferred WARL method. The AER rejected the approach proposed by SA Power Networks because the simple average method:

- resulted in a greater distortion of average remaining lives, relative to 'true' asset lives, than the WARL approach; and
- as a consequence, did not reflect the nature of the assets over their economic lives, as required by clause 6.5.5(b)(1).

SA Power Networks' revised approach produces depreciation schedules that reflect more accurately, than either of the averaging approaches considered by the AER, the actual remaining asset lives of individual assets, since it significantly reduces:

- the impact of the mixture of old and new assets in the same class; and
- the resulting distortion in average remaining lives, relative to the actual remaining lives of the assets in each class.

Put simply, if the AER considers that:

- the most accurate way to depreciate assets is to assess their remaining lives individually; and
- the WARL approach satisfies clause 6.5.5(b)(1) because, while imperfect, it produces average remaining lives that are sufficiently aligned to the remaining lives of the individual assets

it must follow that SA Power Networks' baseline approach also satisfies clause 6.5.5(b)(1), since it significantly lessens the distortion of remaining asset lives when compared to the WARL approach.
The other findings made by the AER in its Preliminary Determination indicate that the depreciation schedules contained in this Revised Proposal otherwise satisfy the requirements of clause 6.5.5(b).

Accordingly, clause 6.5.5(a)(2)(ii) requires that the revised depreciation and tax depreciation schedules be used in calculating SA Power Networks' depreciation allowance and tax allowance. The NER do not permit the rejection of these revised depreciation schedules in favour of:

a) another method preferred by the AER (eg. one that uses the WARL approach); or
b) an alternative method that might also satisfy the requirements of clause 6.5.5(b) (eg. one that uses the WARL of capex only approach).

[535] TransGrid, *2014/15-2018/19 Revenue Proposal*, pages 201-202.

[536] AER, Final Decision, *TransGrid Transmission Determination 2015–16 to 2017–18,* page 5-8 (clause 6A.6.3 of the NER is, in all relevant respects, the same as clause 6.5.5).

14.5 Revised Proposal

The depreciation allowance proposed by SA Power Networks in this Revised Proposal is as follows:

Regulatory depreciation for the 2010–15 RCP is provided in Table 14.3 below.

Table 14.3: Revised regulatory depreciation for the 2010–15 RCP (nominal, $ million)

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Regulatory Depreciation – SCS	74.1	134.7	121.1	118.9	193.1	641.9

Table 14.4: Revised regulatory depreciation for the 2015–20 RCP (nominal, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Straight-line depreciation	235.2	265.3	297.6	328.3	358.0	1,484.5
less inflation indexation on opening RAB	(77.8)	(83.6)	(89.6)	(94.7)	(99.3)	(445.0)
Regulatory Depreciation – SCS	157.3	181.8	208.1	233.6	258.7	1,039.5

The calculations for Tables 14.3 and 14.4 use the AER's RFM and PTRM and apply the same methodology as in the Original Proposal, incorporating the changes noted above as well as the forecast capital expenditure set out in Chapter 7 of this Revised Proposal.

The tax depreciation schedule for the 2010–15 RCP and forecast tax depreciation schedule for the 2015–20 RCP, which have been used to calculate SA Power Networks' allowance for corporate income tax, are shown in Tables 14.5 and 14.6 below.

Chapter 15 provides further details on the allowance for corporate income tax, the calculation of which uses the tax depreciation forecast.

Table 14.5: Revised tax depreciation for the 2010–15 RCP (nominal, $ million)

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Regulatory Tax Depreciation – Standard Control Services	62.4	73.0	93.9	110.2	129.4	468.8

Table 14.6: Revised forecast tax depreciation for the 2015–20 RCP (nominal, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Regulatory Tax Depreciation – Standard Control Services	133.9	165.8	198.1	228.1	258.0	983.8

15. Estimated cost of corporate income tax

15.1 Rule requirements

Clause 6.5.3 of the NER requires the estimated cost of corporate income tax to be calculated for each regulatory year of the 2015-20 RCP in accordance with the following formula:

$ETC_t = (ETI_t \times r_t)(1 - \gamma)$

where:

- ETI*t* is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of SCS if such an entity, rather than the DNSP, operated the business of the DNSP, such estimate being determined in accordance with the post-tax revenue model (**PTRM**);
- r*t* is the expected statutory income tax rate for that regulatory year as determined by the AER; and
- γ is the assumed utilisation of imputation credits.

A key element of these requirements is that the allowance for tax must be that of a 'benchmark efficient entity' for the provision of SCS. Differences arise between these regulatory concepts and actual tax filings because the filings concern real businesses with a different range of activities.

This chapter sets out the methodology for ascertaining the estimated tax costs for SA Power Networks.

15.2 SA Power Networks' Original Proposal

In our Original Proposal, SA Power Networks determined the estimated cost of corporate income tax for each regulatory year of the 2015-20 RCP in accordance with the formula detailed in clause 6.5.3 of the NER.

The Original Proposal included an opening tax asset base at 30 June 2015 of $2,701.7 (nominal, $ million), a closing tax asset base at 30 June 2020 of $4,909.4 (nominal, $ million), and an estimated cost of corporate income tax of $415.8 (nominal, $ million).

15.3 AER's Preliminary Determination

In its Preliminary Determination, the AER accepted SA Power Networks' proposed opening tax asset base as at 1 July 2015, asset classes, straight-line depreciation method and the standard tax asset lives used to calculate regulatory tax depreciation.

However, the AER did not accept SA Power Networks' proposed approach to calculating the remaining tax asset lives at 1 July 2015 and, instead, substituted remaining asset lives calculated using an alternative approach.

The AER did not accept SA Power Networks' proposed value of gamma (being 'γ' in the equation shown in Section 15.1 above) of 0.25, and substituted a value of 0.4.

The AER also revised the regulatory calculation of corporate income tax due to the impact of other aspects of its Preliminary Determination which changed other building block components.

15.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks accepts the AER's preliminary decision with respect to the opening tax asset base and standard tax depreciation lives.

SA Power Networks does not accept the AER's finding with respect to remaining tax asset lives. Our response in relation to remaining tax asset lives is set out in Chapter 14 of this Revised Proposal.

SA Power Networks does not accept the AER's finding with respect to gamma. Our response in relation to gamma is set out in Chapter 13 of this Revised Proposal.

15.5 Revised Proposal

SA Power Networks has calculated a revised tax forecast for the 2015-20 RCP. This calculation uses the AER's roll forward model (**RFM**) and PTRM and applies the same methodology as in the Original Proposal, incorporating the changes to remaining lives discussed in Chapter 14 of this Revised Proposal.

Table 15.1 sets out our revised tax asset base roll forward to 30 June 2015. This incorporates an updated forecast for 2014/15 capital expenditure and adjusts 2009/10 capital expenditure from the Original Proposal to properly include contributions for that year. This is consistent with the methodology approved at the 2010 Determination for establishing the initial tax base at June 2010.

Table 15.1: Tax Asset Base roll forward to 30 June 2015 - SCS (nominal, $ million)

	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Opening Tax Asset Base	948.4	1,039.7	1,344.7	1,675.2	1,973.2	2,223.3
Plus capital expenditure, net of disposals	151.7	367.4	403.5	391.9	360.2	391.6
Less regulatory tax depreciation	(60.5)	(62.4)	(73.0)	(93.9)	(110.2)	(129.4)
Closing Tax Asset Base	1,039.7	1,344.7	1,675.2	1,973.2	2,223.3	2,485.4

Table 15.2 sets out the revised tax asset base roll forward to 30 June 2020.

Table 15.2: Tax Asset Base roll forward to 30 June 2020 - SCS (nominal, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20
Opening Tax Asset Base	2,485.4	2882.0	3, 283.2	3,644.1	3,978.7
Plus capital expenditure, net of contributions and disposals	530.4	567.0	559.0	562.7	545.4
Less regulatory tax depreciation	(133.9)	(165.8)	(198.1)	(228.1)	(258.0)
Closing Tax Asset Base	2,882.0	3,283.2	3,644.1	3,978.7	4,266.1

The estimate of taxable income for each regulatory year of the 2015-20 RCP (that would be earned by a benchmark efficient entity) as a result of the provision of SCS (being 'ETI_t' in the equation in Section 15.1 above) for the purposes of clause 6.5.3 of the NER, is set out in Table 15.3.

Table 15.3: Taxable income for the 2015-20 RCP (nominal $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20
Standard Control Services	356.0	363.6	375.8	392.6	407.9

Adopting a corporate tax rate (r_t) of 30% and ascribing a utilisation value for imputation credits (γ) of 0.25 (as discussed in Chapter 13 of this Revised Proposal), the estimated cost of corporate income tax (being 'ETC_t' in the equation in Section 15.1 above) for each regulatory year of the 2015-20 RCP, is set out in Table 15.4.

Table 15.4: Estimated cost of corporate income tax for the 2015-20 RCP (nominal, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20
Standard Control Services	80.1	81.8	84.6	88.3	91.8

Page left blank intentionally

16. Revenue and pricing

16.1 Rule requirements

Part C of Chapter 6 of the NER outlines the requirements of a building block determination, which is the component of a distribution determination relevant to the regulation of Standard Control Services (**SCS**).

Clause 6.3.2 of the NER provides that a building block determination specifies, amongst other things, a Distribution Network Service Provider's (**DNSP's**) annual revenue requirement for each regulatory year of the regulatory control period (**RCP**).

Clause 6.4.3 of the NER provides that the annual revenue requirement in a regulatory year, is determined using a building block approach, under which the building blocks are:

- indexation of the regulatory asset base;
- a return on capital for that year;
- the depreciation for that year;
- the estimated cost of corporate income tax of the provider for that year;
- the revenue increments and decrements (if any) for that year arising from the application of the efficiency benefit sharing scheme, the service target performance incentive scheme, and the demand management and embedded generation connection incentive scheme (**DMEGCIS**) or small-scale incentive scheme (**SSIS**)*;
- the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous RCP; and
- the forecast operating expenditure of that year.

*Note: In its F&A, the AER determined that it will only apply the Demand Management Innovation Allowance component of the DMEGCIS and it would not apply any SSIS in the 2015-20 RCP.

Clause 6.4.4 of the NER provides that, where an asset is used to provide both SCS and other services ('shared asset'), and the DNSP recovers part of the costs of that asset through charging for the other services, then the AER can reduce the annual revenue requirement by an amount to reflect this cost recovery. This is the first RCP where this 'shared assets' Rule applies.

Clause 6.5 of the NER contains the specific requirements for the building block components, which are used to establish an unsmoothed revenue requirement. The resulting price path to deliver this revenue is then smoothed with an X factor or factors in accordance with the requirements of clause 6.5.9. One of these requirements is to minimise the variance between the expected revenue of the last year of the RCP and the annual revenue requirement determined for that year. However, a transitional arrangement in clause 11.60.4(h) of the NER removes this requirement for this RCP.

Clause 6.12.1 of the NER requires the AER to make certain constituent decisions relating to a distribution determination. For this Revenue and Pricing section of our Revised Proposal, the following clauses of the NER are relevant:

- Clause 6.12.1(2) of the NER requires the AER to make a decision on SA Power Networks' building block proposal including the annual revenue requirement for SA Power Networks for each regulatory year;

- Clause 6.12.1(12) of the NER requires the AER to make a decision on the form of control mechanisms (including the X factor) for SCS (to be in accordance with the relevant Framework and Approach Paper) and on the formulae that give effect to those control mechanisms;
- Clause 6.12.1(13) of the NER requires the AER to make a decision on how compliance with the control mechanism is to be demonstrated;
- Clause 6.12.1(17) of the NER requires the AER to make a decision on the procedures for assigning retail customers to tariff classes or reassigning customers from one tariff class to another;
- Clause 6.12.1(19) of the NER requires the AER to make a decision on how SA Power Networks is to report on its recovery of designated pricing proposal charges for each regulatory year, including adjustments in subsequent pricing proposals for over or under recovery of those charges; and
- Clause 6.12.1(20) of the NER requires the AER to make a decision on how SA Power Networks is to report on its recovery of jurisdictional scheme amounts for each regulatory year, including adjustments in subsequent pricing proposals for over or under recovery of those charges.

The AEMC in its Distribution Network Pricing Arrangements Rule change amended the Distribution Pricing Rules in Part I of the NER in December 2014. However, these new Rules will not apply to SA Power Networks' pricing proposals for the 2015/16 and 2016/17 regulatory years.

In accordance with the new Rules, SA Power Networks will lodge a Tariff Structure Statement (**TSS**), with the AER in November 2015 that will apply to the 2017/18 regulatory year.

16.2 SA Power Networks' Original Proposal

Chapter 29 of SA Power Networks' Original Proposal set out our calculation of annual revenue requirements for the provision of SCS for each year of the 2015-20 RCP and the X factors to be applied as part of the revenue cap for the provision of SCS.

SA Power Networks proposed a total revenue requirement for the 2015-20 RCP of $4782 (nominal, $ million) for the provision of SCS. We also proposed an X factor of 4.3% for the 2015/16 regulatory year and X factors of zero for the subsequent years of the RCP.

SA Power Networks proposed that SCS prices for each year of the 2015-20 RCP be made equal to deliver a relatively smooth price path within the 2015-20 RCP. Indicative annual charges for SCS were outlined in Table 29.4 of our Original Proposal. These charges are replicated below in Table 16.1.

Table 16.1: Original Proposal indicative annual charges for SCS ($ nominal, excluding GST)

Tariff class	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
High voltage business (2.7 MVA demand, 10 GWh pa)	408,400	400,847	411,069	421,551	432,300	443,324
Low voltage business (360 kVA demand, 1 GWh pa)	72,402	71,063	72,875	74,733	76,639	78,593
Medium business (100 MWh pa, 50% peak)	9,875	9,692	9,939	10,193	10,453	10,719
Small business (10 MWh pa)	1,238	1,215	1,246	1,278	1,310	1,344
Low voltage residential (5 MWh pa)	639	627	643	660	677	694
Controlled load (2.5 MWh pa)	97	95	97	100	102	105

Section 29.5 of the Original Proposal also outlined SA Power Networks' network pricing strategy to move towards more cost-reflective pricing, with initiatives including:

- increasing the demand component in small customer tariffs;
- better signalling network costs to customers requiring air-conditioning, solar PV panels and/or battery storage to promote efficient changes to demand for network services; and
- special tariff provisions for the most vulnerable of small customers assigned to cost-reflective tariffs.

16.3 AER's Preliminary Determination

The AER's Preliminary Determination Overview document and Attachment 1 to that document summarise the AER's decision on the annual revenue requirement. The AER's preliminary decision is that SA Power Networks can recover $3,211 (nominal, $ million) from customers over the 2015-20 RCP. This is $1,534 (nominal, $ million) lower than the amount proposed by SA Power Networks. The main reductions, in nominal terms, are due to:

- $554 million less return on capital allowed;
- $860 million less capital expenditure allowed;
- $346 million less operating expenditure allowed;
- $402 million less depreciation allowed (due to a combination of lower capital expenditure and a change in calculating the remaining asset lives); and
- $227 million less tax allowance, reflecting the above changes and the AER adopting a higher value of imputation credits (gamma).

Table 16.2 below summarises the proposed and allowed revenues.

Table 16.2: Original Proposal and allowed SCS revenue (nominal, $ million)

Revenue building block	Original Proposal	Preliminary Determination	Difference
Return on capital	1,738.7	1,184.6	-554.1
Regulatory depreciation	936.0	533.7	-402.3
Operating expenditure	1,680.1	1,334.3	-345.8
Revenue adjustments	11.2	-5.6	-16.8
Net tax allowance	415.8	189.3	-226.5
Annual revenue requirement (unsmoothed)	4,781.9	3,236.3	-1,545.6
Annual expected revenue (smoothed)	**4,744.9**	**3,211.3**	**-1,533.6**

The AER's preliminary decision accepted SA Power Networks' opening value for the regulatory asset base (RAB) of $3,829.4 (nominal, $ million) as at 1 July 2015. The forecast depreciation approach will be used to establish SA Power Networks' opening RAB at the commencement of the 2015-20 RCP on 1 July 2020.

The AER's preliminary decision did not accept SA Power Networks' proposed rate of return of 7.62% (nominal vanilla) and instead determined an allowed rate of return of 5.45%.

The AER's preliminary decision did not accept SA Power Networks' proposed value of imputation credits for tax paid at the company level of 0.25 and instead the AER adopted a value of 0.4.

With regard to depreciation, the AER's preliminary decision accepted SA Power Networks' proposed asset classes, the straight line depreciation method and most standard asset lives. However, the AER did not accept SA Power Networks' proposed average depreciation approach to calculate the remaining asset lives at 1 July 2015 and instead adopted a weighted average approach. The AER's preliminary decision on depreciation also incorporates the AER's lower capital expenditure allowance.

The AER's preliminary decision smooths the annual revenue each year by adopting X factors which provide for substantial average distribution charge reductions of 27.6% in 2015/16, 9.9% in 2016/17, 2.5% in 2017/18 and 2018/19 and 1.1% in 2019/20.

In particular, the AER's Preliminary Determination sets allowed revenue for 2015/16 of $682 million. Pricing for 2015/16 has been prepared by SA Power Networks and submitted to the AER that complies with this income target. Charges have been reduced by 27.3% on average. The 2015/16 Annual Pricing Proposal has more detailed information on these charges. The tables below incorporate the outcome of these proposed tariffs.

16.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks has reviewed the AER's Preliminary Determination on each of the building block components and our responses on each are discussed in detail in other sections of this Revised Proposal.

We have adopted the AER's preliminary decisions on revenue controls and side constraint removal, and note the AER's decision as to the procedures to be followed for assigning or reassigning customers to tariff classes (which procedures are set out in Attachment 14 to the Preliminary Determination).

We have adopted the AER's annual reporting requirements set out in Attachment 14 of its Preliminary Determination.

16.5 Revised Proposal

16.5.1 Building block revenue components for SCS

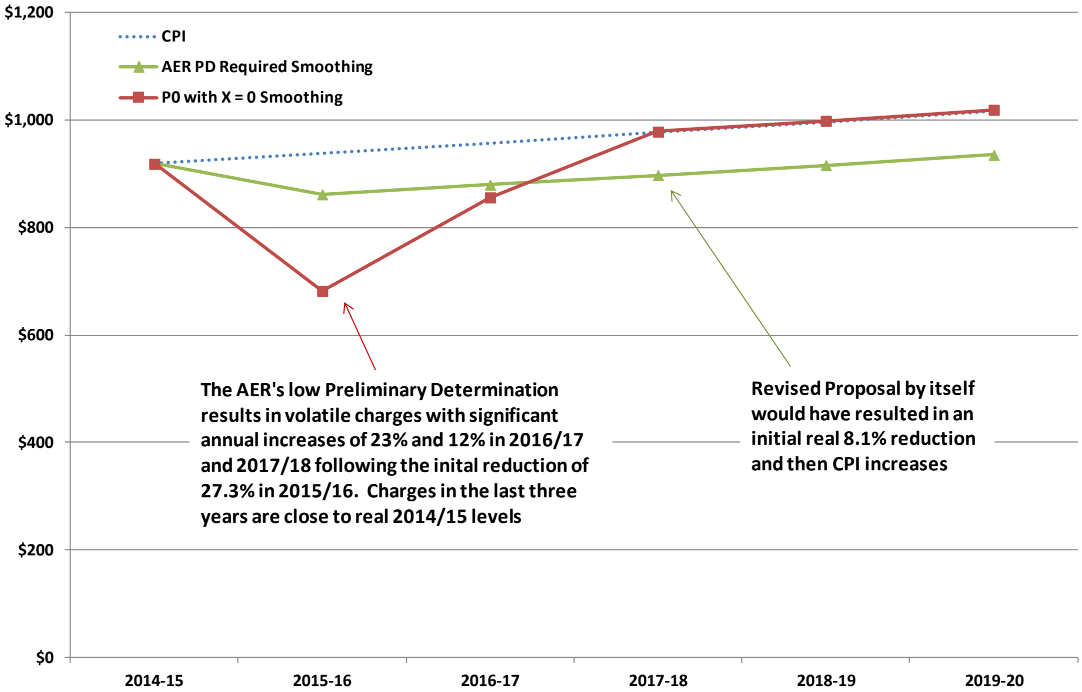
Table 16.3 below summarises our revised building block proposal. The smoothed revenue and X factor to apply in 2015/16 are as determined in the AER's Preliminary Determination. All other components have been revised, using the AER's Post-Tax Revenue Model (**PTRM**). SA Power Networks' completed SCS PTRM is provided as Attachment P.1.

Table 16.3: Revised Proposal SCS building block revenue (nominal, $ million**)**

Revenue building block	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Return on capital	268.0	287.8	308.4	326.2	341.9	1,532.4
Regulatory depreciation	157.3	181.8	208.1	233.6	258.7	1,039.5
Operating expenditure	277.2	294.8	305.0	317.8	329.6	1,524.4
Revenue adjustments	-1.0	-5.4	-2.2	4.7	0.7	-3.2
Net tax allowance	80.1	81.8	84.6	88.3	91.8	426.5
Annual revenue requirement (unsmoothed)	781.7	840.8	903.7	970.6	1,022.7	4,519.5
Annual expected revenue (smoothed)	**682.0**	**856.1**	**978.5**	**998.6**	**1,019.2**	**4,534.5**
X factors (real SCS revenue)	27. 3%	-23.0%	-12.0%	0%	0%	

Figure 16.1 shows two smoothed revenue paths through to 2019/20. If the Preliminary Determination had been made on the basis of the Revised Proposal, SA Power Networks would have delivered an initial P_0 reduction in SCS charges of 8.1% with no real change in subsequent years (ie $X_{1\text{-}4}$ = 0%). However, as the AER's Preliminary Determination reduced 2015/16 SCS charges by 27.3% real, catch-up increases are required in both 2016/17 (23.0%) and in 2017/18 (12%). Charges in the final three years (2017/18 to 2019/20) would be at similar real pricing levels to those of 2014/15.

Figure 16.1: Revised Proposal Smoothed SCS Revenue by Year (nominal $ million)



In accordance with the AER's Rate of Return Guideline, the AER will calculate the actual cost of debt each year. This means the return on capital revenue building block and hence the total unsmoothed revenue, X factors, service target performance incentive scheme amounts and total smoothed revenue to apply in the 2016/17 – 2019/20 years will be updated each year. SA Power Networks' annual pricing proposals will reflect these changes.

16.5.2 Indicative charges for SCS

The indicative charges for SCS outlined in this section are forecast to recover revenues equal to, in net present value terms, the annual revenue requirement (unsmoothed) for SCS set out in Table 16.4.

Table 16.4: Revised Proposal SCS building block revenue (nominal, $ million)

Revenue building block	2015–16	2016–17	2017–18	2018–19	2019–20
Annual expected revenue (smoothed)	682.0	856.1	978.5	998.6	1,019.2

Indicative annual charges for each tariff class for the next RCP are shown in Table 16.5. These charges also assume that current pricing relativities between tariffs established in the 2015/16 Pricing Proposal remain.

Table 16.5: Revised Proposal indicative annual charges for SCS (nominal, $ excl GST)

Tariff class	2015/16	2016/17	2017/18	2018/19	2019/20
High voltage business (2.7 MVA demand, 10 GWh pa)	295,148	361,343	405,228	413,532	418,660
Low voltage business (360 kVA demand, 1 GWh pa)	50,395	61,700	69,194	70,612	71,484
Medium business (100 MWh pa, 50% peak)	8,024	9,825	11,019	11,244	11,382
Small business (10 MWh pa)	1,000	1,224	1,373	1,401	1,418
Low voltage residential (5 MWh pa)	491	601	674	687	696
Controlled load (2.5 MWh)	78	95	107	109	110

16.5.3 Other pass through costs

In addition to SA Power Networks' SCS charges, SA Power Networks customers may be levied certain alternative control services (**ACS**) metering charges. These metering charges are discussed in Chapter 17 of this Revised Proposal. SA Power Networks customers will also be levied transmission charges and charges to pay for the South Australian Government's solar photo-voltaic (**PV**) feed in tariff (**FiT**) scheme.

Transmission charges

The total network charges paid by SA Power Networks' customers include payments to ElectraNet SA for all of the transmission network service providers that support South Australia, including MurrayLink and interstate transmission providers. The AER regulates these charges, with ElectraNet's next determination applying from July 2018.

For the purpose of identifying likely total network payments by customers, the 2015/16 charges have been escalated by CPI and the revenue cap X-factor that applies to ElectraNet. This should be indicative of likely trends in these prices, although prices will vary from year to year depending on sales volumes, service incentive scheme payments and the dollar amounts from inter-regional trading differences which are required to be returned to customers via a discount to transmission payments. Table 16.6 below indicates these charges.

Table 16.6: Revised Proposal indicative transmission charges (nominal, $ million)

Transmission charges	2015/16	2016/17	2017/18	2018/19	2019/20
ElectraNet/MurrayLink revenue cap	328.2	344.9	362.5	370.0	377.6
TUoS* charges to SA Power Networks customers	279.0	293.2	308.1	314.5	321.0

Note: *TUoS = Transmission use of system

It has also been assumed for this Revised Proposal that following ElectraNet SA's next Revenue Determination in 2018, transmission prices in 2018/19 and 2019/20 will increase with CPI only.

Jurisdictional schemes (Solar PV FiT payments)

The South Australian Government has three Solar PV FiT schemes, all of which are now closed to new applications:

- A '44 cent' scheme that expires in June 2028;
- A '44 cent step' scheme that also expires in June 2028; and
- A '16 cent' scheme that expires in September 2016.

Payments and recoveries are expected to continue at $90.1 million per annum through to 2020, and conclude in 2028. Table 16.7 below indicates these charges.

Table 16.7: Revised Proposal Solar PV FiT charges (nominal, $ million)

PV FiT charges	2015/16	2016/17	2017/18	2018/19	2019/20
Solar PV FiT charges to customers	116.7	100.2	90.1	90.1	90.1
44 cent scheme	16.5	16.5	16.5	16.5	16.5
44 cent step scheme	73.6	73.6	73.6	73.6	73.6
16 cent scheme	40.4	10.10	-	-	-

16.5.4 Total network charges forecast for recovery

The total recovery from all SA Power Networks customers' network charges will comprise the SCS (distribution services) charges, and the pass-through charges for transmission and Solar PV FiT. Table 16.8 below summarises the SCS, transmission and Solar PV FiT charges.

Table 16.8: Revised Proposal total network charges (nominal, $ million)

Components	2015/16	2016/17	2017/18	2018/19	2019/20
Standard Control Services	682.0	856.1	978.5	998.6	1,019.2
Transmission charges	279.0	293.2	308.1	314.5	321.0
Solar PV Fit schemes	116.7	100.2	90.1	90.1	90.1
Total network charges	**1,077.6**	**1,249.5**	**1,376.7**	**1,403.2**	**1,430.3**
X factors (real network charges)	21. 8%	-14.2%	-7.7%	-0.2%	-0.2%

Indicative annual network charges for typical customers for the next RCP are shown in Table 16.9. These charges also assume that current pricing relativities between tariffs established in the 2015/16 Pricing Proposal remain.

Table 16.9: Revised Proposal Indicative annual network charges ($ nominal, excl GST)

Tariff class	2015/16	2016/17	2017/18	2018/19	2019/20
High voltage business (2.7 MVA demand, 10 GWh pa)	543,489	603,294	647,491	660,015	667,419
Low voltage business (360 kVA demand, 1 GWh pa)	82,248	92,359	99,635	101,550	102,676
Medium business (100 MWh pa, 50% peak)	12,355	13,957	15,094	15,384	15,551
Small business (10 MWh pa)	1,474	1,672	1,812	1,847	1,867
Low voltage residential (5 MWh pa)	732	829	897	915	925
Controlled load (2.5 MWh pa)	135	150	162	165	167

16.5.5 Indicative charges forecast for network services

We have not amended our position on network pricing from our Original Proposal. Our intention is to continue our ongoing tariff reforms to move to more cost-reflective distribution pricing. Under the 2015/16 Pricing Proposal, we have completed the implementation of cost-reflective pricing to all large customers, with some of these customers using a five-year transition pathway to full-cost reflectivity.

During the 2015-20 RCP our proposed tariff reform includes:

- developing a demand component in small customer tariffs;
- better signalling network costs to residential customers with either permanent or periodic residency; and
- special tariff provisions for the most vulnerable of residential customers assigned to cost-reflective tariffs.

We will consult with customers and stakeholders on our proposal to progressively implement cost-reflective tariffs for small customers from July 2017 when we develop our Tariff Structure Statement (**TSS**) later in 2015. We will consider the form of the cost-reflective tariffs and the speed at which customers will transition to them over time. We submit our TSS to the AER for approval in November 2015. The final approval of the TSS by the AER will occur by January 2017.

Page left blank intentionally

17. Alternative control services (ACS)

17.1 Control mechanism

17.1.1 Rule requirements

Clause 6.12.1 of the NER requires the AER to make a number of constituent decisions as part of a distribution determination. The decisions relevant to the control mechanism for alternative control services (**ACS**) for the 2015-20 RCP are as follows:

- Clause 6.12.1(12) requires the AER to make a decision on the form of the control mechanisms for ACS (to be in accordance with the relevant framework and approach paper) and on the formulae that give effect to those control mechanisms; and
- Clause 6.12.1(13) requires the AER to make a decision on how compliance with a relevant control mechanism is to be demonstrated.

17.1.2 SA Power Networks' Original Proposal

In Section 19.2 of our Original Proposal, we noted that the AER decided in its Framework and Approach Paper (**F&A**)[537] that it would apply a price cap form of control to SA Power Networks' ACS in the 2015-20 RCP. This decision is binding on the AER and SA Power Networks. Caps on the prices of individual services are the same as a schedule of fixed prices except that SA Power Networks may set prices below the specified prices.

Under a price cap, the price for each service can be escalated each year by no more than the rate of change in the CPI, but can be modified by adjustments for the 'X' factor and other cost impacts. These adjustments would form a component of SA Power Networks' annual pricing proposal in respect of ACS submitted to the AER for approval for each regulatory year of the 2015-20 RCP.

Under the new classification of services for ACS to apply in the 2015-20 RCP, ACS tariffs will now include a much greater component of fixed costs than previously, particularly those relating to SA Power Networks' tax liability and overheads allocated via the Cost Allocation Method (**CAM**). SA Power Networks' Original Proposal noted that there is a risk of under-recovery of these fixed costs from existing customers associated with inaccurate forecasting of customer numbers, particularly if customers 'churn' to another meter provider when or even before meter contestability for small customers commences.

This risk can be mitigated by the use of meter transfer and exit fees. SA Power Networks' Original Proposal included a new transfer fee in respect of smart-ready meters and a new exit fee in respect of Type 6 standard meters. Our Original Proposal also noted other options could obviate the requirement for meter transfer fees but we believed our approach to using transfer and exit fees was efficient and transparent and best met the long term objectives reflected in the National Electricity Objective.

[537] AER, *Final framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, April 2014.

17.1.3 AER's Preliminary Determination

In its Preliminary Determination, the AER classified Type 5 and 6 metering services, and exceptional large customer metering services, as ACS and determined that the control mechanism for ACS metering services would be caps on the prices of individual services.

The AER's Preliminary Determination approves two types of metering services charges:

- upfront capital charges for all new and upgraded meters installed from 1 July 2015; and
- annual charges comprising two components:
  - a capital component intended to recover the costs associated with the metering asset base (**MAB**); and
  - a non-capital component to recover ongoing operating expenditure and tax costs.

The AER did not approve any meter exit fees for SA Power Networks' regulated meters.

The control mechanism formula for the charges the AER approved is set out on page 16-11 of the Preliminary Determination. The formula sets price caps for the upcoming regulatory year by adjusting the previous year's prices for CPI and an 'X' factor, determined by the AER. The formula also contains an 'A' factor, allowing for other annual adjustments. However, for the annual metering charges, the AER has set the X factors and A factor to zero for the 2015-20 RCP. X-factors have been determined for the upfront charges.

SA Power Networks must annually adjust individual price caps in accordance with this formula and provide a copy of its published price list for that year to the AER.

17.1.4 SA Power Networks' response to AER Preliminary Determination

Control mechanism and formula

SA Power Networks accepts the AER's decision that the control mechanism for ACS charges for the 2015-20 RCP will be in the form of price caps set by the AER. This is consistent with the F&A published by the AER in April 2014.

SA Power Networks notes the price control formula as set out on page 16-11 of the AER's Preliminary Determination, and for annual metering charges, the AER's decision to set the X and A factors to zero for the 2015-20 RCP.

SA Power Networks does not accept this decision in relation to the AER's price control formula, and the X and A factors, to apply for the 2015-20 RCP, as the AER has not provided details in respect of its method for determining these factors.

The AER provides its rationale for the annual adjustment to the upfront meter installation charges in Section 16.1.5.3 to the Preliminary Determination. SA Power Networks believes the same cost influences apply to both the installation of meters and the maintenance and reading of meters, and it is therefore appropriate for the same X factors to apply to annual metering charges to reflect the growth in labour costs that have been applied to the upfront meter installation charges.

Neither do we accept the A factor being set to zero. A non-zero A factor would allow the AER to make annual adjustments for any under or over-recovery of ACS revenue which may arise during the 2015-20 RCP. We discuss this further, where we explain that we expect a significant under-recovery to occur in 2015/16. As noted below, the AER has made arithmetic errors in the determination of the upfront meter installation charge for all Type 5 meters and has not allowed for any contribution to overheads or return for either Type 5 or Type 6 meter installations. Even if the AER corrects these errors in its Final Determination, SA Power Networks will have no recourse to the customers that have had these meters installed during 2015/16, who have paid the price set by the AER. Furthermore, it is not possible to reasonably estimate the number or specification of these meters that might be installed during 2015/16. SA Power Networks believes that this is a compelling example of where the A factor could be used to 'true up' any actual losses caused by these errors.

Further, the level of meter churn will affect certain per unit costs such as meter reading for remaining meters.

SA Power Networks will demonstrate compliance with the control mechanism and formula in May each year when it lodges its annual pricing proposals with the AER for approval.

Upfront charges

SA Power Networks notes the AER's decisions to establish upfront capital charges for all new and upgraded meters from 1 July 2015. This is a significant departure from SA Power Networks' long-standing policy, which provided the meter free to new customers receiving a 'basic' connection service[538] and only charged the incremental cost of a non-standard meter, if the customer elected to receive a non-basic service.

In determining the upfront charges, the AER has accepted SA Power Networks' non-material costs, which it noted were the lowest relevant rates in the NEM,[539] but substituted its own unit costs for certain meter types.

In particular, the AER substituted a price of $100 for a three-phase Type 6 accumulation meter, which is well below the lowest price available to SA Power Networks from its current suppliers. In April 2015, SA Power Networks sought proposals from all meter vendors currently supplying the Australian market, through a competitive tender process. One supplier offered a price comparable to that used by the AER however, this supplier is currently not an existing supplier to SA Power Networks.

Taking the cheapest vendor's quoted lead times into account, we will not be able to commence installing meters using this lower cost meter before January 2016, and SA Power Networks will therefore suffer a material loss on every three-phase Type 6 meter installed before then.

The AER's decision in respect of the three-phase Type 6 meter unit cost effectively obliges SA Power Networks to change suppliers for this type of meter. Moving to a new supplier for this type of meter will require time and cost to negotiate supply terms, and to establish this vendor in our systems, but SA Power Networks has not made an allowance for these additional costs in this Revised Proposal. Adding a new meter to our fleet will require a significant capital investment by SA Power Networks, including the purchase and deployment of the new vendor's meter programming devices and associated software for all field depots, conformance testing, and training. These costs have been added to this Revised Proposal, along with the additional operating costs associated with software maintenance for the new meters.

[538] A basic connection service is a low voltage connection (or proposed connection) requiring no greater than 63 Amps per phase between SA Power Networks' distribution system and a customer's premises. It may include a small embedded generator generating no more than 10kVA per phase or 5kVA for Single Wire Earth Return (**SWER**) connections.
[539] AER, *Preliminary Decision: SA Power Networks determination 2015−16 to 2019−20*, April 2015, page 16-35.

Annual metering charges

SA Power Networks also notes the AER's decision to implement new annual metering charges that comprise two components: a **capital component** and a **non-capital component**.

The AER has applied this two-part structure to three different meter types, resulting in six new annual metering charges. SA Power Networks currently has three regulated annual metering charges. The implementation of the AER's six new charges will add significant complexity to SA Power Networks' billing arrangements. Billing system and other system changes to implement this new billing structure are being developed but are not expected to be implemented before January 2016. Additional costs for these changes have been included in our revised capital expenditure forecasts.

Until these changes are implemented, SA Power Networks will continue its current billing practice, which is to bundle the capital and non-capital meter charges in with the customer's supply charges. Those customers who should not incur any meter charges (ie those customers who did not have an SA Power Networks' regulated meter at 30 June 2015) or should incur only one metering component (ie customers who connect after 1 July 2015, or existing customers who churn to another metering provider) will be rebated accordingly. All of these transactions will be made with the customer's retailer.

The AER's rationale for establishing this new two-part tariff structure, and how the charges would be levied, were discussed in Section 4.3.1 of this Revised Proposal. SA Power Networks agrees with the AER's intention to keep DNSPs financially 'whole' through the transition to expanded metering contestability. The AER has structured tariffs so that the return on and of capital associated with the MAB as at 1 July 2015 may be recovered through the capital component of the annual metering charge.

However, SA Power Networks does not agree with AER's allocation of the revenue building blocks between the 'capital' and 'non-capital' metering charges. The revenue building blocks comprise:

- return on capital;
- return of capital;
- operating expenditure; and
- tax liability.

The AER has allocated the return on capital and return of capital building blocks to the capital component of the annual metering charge. The annual capital metering charge will be paid by all customers with a SA Power Networks' regulated meter at 1 July 2015, irrespective of whether they remain a SA Power Networks' meter customer or churn to another metering provider.

The AER has allocated the operating expenditure and tax liability building blocks to the non-capital component of the annual metering charge. This charge will be paid by all customers that have a regulated meter. If a customer churns to another metering provider, they can avoid paying this component (but will still pay the capital component).

SA Power Networks strongly disagrees with the allocation of the tax liability building block to the non-capital component of the annual metering charge. The tax liability is entirely a product of the return on capital and the difference between regulatory and tax depreciation.[540] It is therefore erroneous to characterise the tax liability as a non-capital cost.

[540] Under the new regime where all new meters are paid for upfront, there will be no customer contributions.

Further, the tax liability is essentially a fixed cost for the term of the relevant RCP. The tax liability is interminably linked to the return on capital and relevant regulatory depreciation. It does not make sense to include the fundamental drivers of this cost in the capital (fixed) tariff component while allocating the outcome to the non-capital (variable) tariff component. Furthermore, including the tax liability in the non-capital component of the annual metering charge puts this essentially fixed cost at risk of meter churn, which materially undermines the AER's stated intention of keeping DNSPs financially 'whole'.

SA Power Networks believes it is necessary to allocate the tax liability building block to the capital tariff component. The non-capital charge is appropriate for the recovery of variable costs that are reasonably considered to be avoidable if customers churn to other meter providers. As noted above, this is not the case for the tax liability.

SA Power Networks expects to experience a significant and fast growing level of meter churn from 2015/16 onward. We are currently in discussions with a major retailer that has already commenced rolling out smart meters in South Australia and has formally advised that they plan to replace a significant number of meters in 2015/16. Consequently, we will be under-recovering fixed costs in 2015/16. This issue must be addressed in the AER's Final Determination in October 2015.

In a similar vein, corporate overheads are a fixed cost, allocated as a lump sum to ACS through the AER-approved CAM. The most effective way for these costs to be recovered is by separately identifying and including them in a cost build up, and then allocating this cost item to the 'fixed' or capital component of the annual metering tariff so that they are not at risk of stranding due to churn. However, for the Revised Proposal, in the interests of efficiency we have broadly accepted the AER's base step trend approach to the assessment of operating costs. SA Power Networks has therefore had to accept that our corporate overhead allocation will be under-recovered due to meter churn during the 2015-20 RCP.

Exit Fees

SA Power Networks accepts that the AER has not approved any meter exit fees for SA Power Networks' regulated meters during the 2015-20 RCP. But, as mentioned in Section 4.4.1 of this Revised Proposal, the AER should note that this does not prevent SA Power Networks from continuing to charge a meter exit fee for negotiated distribution services (**NDS**) meters.

AER Errors

In accordance with the NER, we were required to lodge our 2015/16 'initial pricing proposal' with the AER by 21 May 2015. This pricing proposal includes our ACS prices for 2015/16, which are in accordance with the AER's Preliminary Determination.

However, SA Power Networks believes that the AER has made a number of errors, omitted certain costs, and made inappropriate allocations, within the detailed calculations that underpin the metering charges it has set for the 2015-20 RCP. These errors and omissions are discussed later in this chapter and their proposed rectification forms part of our Revised Proposal.

In mid-May 2015, we raised some of these concerns with the AER and specifically asked whether the clear omission of the $11 (June 2015, $ million) of ACS operating expenditure (associated with reclassification of meter data services from SCS to ACS) could be rectified prior to the 2015/16 tariffs being submitted for approval. Unfortunately, the AER's position was that it was not possible to accept and rectify errors prior to the setting of 2015/16 tariffs and that these errors should be addressed in our Revised Proposal.

We expect that the AER will address these errors in its Final Determination in October 2015 by revoking the 2016/17-2019/20 metering charges published in its Preliminary Determination and substituting new charges to apply for those four years in its Final Determination. SA Power Networks has provided its proposed tariffs for 2016/17 to 2019/20 in Section 17.4.5 of this chapter.

17.1.5 Revised Proposal

In summary, our Revised Proposal accepts the AER's decisions that:

- price caps will apply to ACS (metering services) for the 2015-20 RCP;
- the price control formula will be as set out on page 16-11 of its Preliminary Determination for the 2015-20 RCP. However, the AER should not set the A factor to zero and should leave it as a variable to account for under-recovery of fixed costs;
- the annual metering charges to apply in 2015/16 are as set out on page 16-52 of its Preliminary Determination; and
- the upfront metering charges for new and upgraded meters to apply in 2015/16 will be consistent with those set out on page 16-52 of its Preliminary Determination.

In formulating the prices for ACS, we believe the AER has made a number of errors of detail and omission which are discussed later in this chapter. The AER must consider these matters in its Final Determination, and substitute new prices that will apply from 2016/17. On this basis, we do not accept:

- the annual metering charges for 2016/17-2019/20 as set out on page 16-52 of the AER's Preliminary Determination; and
- the upfront metering charges for new and upgraded meters for 2016/17-2019/20 as set out on page 16-52 of the AER's Preliminary Determination.

Instead we propose new prices for these four years which are outlined in Section 17.4 of this Revised Proposal.

17.2 Capital expenditure

17.2.1 Rule requirements

There is no requirement in the NER for the AER to make a constituent decision relating to ACS capital expenditure. There is also no requirement in the NER governing how ACS capital expenditure should be determined.

17.2.2 SA Power Networks' Original Proposal

In Section 20.9 of our Original Proposal, SA Power Networks described our proposed ACS capital expenditure. This expenditure comprised the costs of installing new meters, of replacing non-compliant and failed meters, and of making material repairs to metering installations.

SA Power Networks took a 'bottom-up' approach to determining forecast capital expenditure by forecasting volumes and determining average unit costs for each of the following services:

- new installations;
- replacement of existing meters; and

- upgrading existing meter installations.

To support our strategy to transition to more cost-reflective demand-based tariffs for residential and small business customers in the 2015-20 RCP and avoid wasteful further investment in obsolete accumulation meters, SA Power Networks proposed that all new and replacement meters in the 2015-20 RCP be:

- capable of recording interval meter data and measuring maximum demand; and
- designed to be upgradeable in the future to enable remote reading and advanced functions.

This strategy was devised at a time when the South Australian Government had canvassed a draft policy of installing 'smart-ready' meters by default for new and replacement meters. It was also devised when proposed arrangements and timing for the introduction of metering contestability during the 2015-20 RCP were less clear.

For demand tariffs to be effective for customers in terms of supporting their ability to respond to cost reflective price signals, relevant meters must be read monthly. We had forecast that by 2017/18 we would have a critical mass of customers on monthly demand tariffs and it would be cost effective to transition from manually reading meters on a quarterly basis to reading them on a monthly basis.

The proposed capital expenditure to implement this strategy, reflected:

- a small unit cost increase reflecting the cost differential between smart-ready and accumulation meters;
- forecast volumes of new, replacement and upgraded meters; and
- IT expenditure including replacement of 'business-as-usual' hand-held meter reading devices and a one-off increase for additional devices in 2017/18 to facilitate the transition to monthly meter reading.

17.2.3 AER's Preliminary Determination

In the six months between the lodgement of our Original Proposal and the AER making its Preliminary Determination, the policy setting for metering contestability has progressed. In particular:

- the Australian Energy Market Commission (**AEMC**) has issued a draft Rule change for consultation which clarifies many of the proposed arrangements for the introduction of metering contestability and sets the commencement date as 1 July 2017; and
- the draft Rule change proposes a national minimum specification that will require all meters installed after 1 July 2017 to be remotely read interval meters. This is a departure from the original concept of a purely 'opt-in' approach, and removes the need for jurisdictional 'new and replacement' policies such as the South Australian Government's proposed 'smart-ready' meter policy.

The AER's decision in the Preliminary Determination on ACS takes these policy developments into account.

The AER did not approve our proposed tariff and metering reform package which would have been implemented ahead of full metering competition commencing. Consequently, the AER did not accept SA Power Networks' forecast ACS capital expenditure.

More specifically, the AER:

- decided that all new regulated meter connections installed after 1 July 2015 will be paid for up front and the costs expensed rather than capitalised as they have been previously;
- determined that there was not sufficient evidence that the benefits of installing interval capable meters outweighed the additional capital expenditure required. The AER approved replacement expenditure for accumulation meters only;
- did not accept SA Power Networks' unit cost forecast for some meter types;
- accepted SA Power Networks' non-material unit costs;
- accepted SA Power Networks' forecast for 'reactive' meter replacement volumes;
- did not accept SA Power Networks' forecast for 'proactive' meter replacement volumes. The AER substituted its own forecast volumes, based on historical volumes replaced by SA Power Networks;
- did not accept any of the 'other planned replacements' meter volumes proposed by SA Power Networks; and
- did not accept any of SA Power Networks' associated forecast IT expenditure.

17.2.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks accepts the AER's decision to not provide funding for smart-ready metering. As noted earlier, our Original Proposal for smart-ready metering was made when the South Australian Government had formulated a draft policy for all new and replacement meters to be smart-ready as default and the timing and arrangements for introducing metering contestability were less clear. In that context, we developed our original metering plans to support our strategy to introduce cost reflective demand-based tariffs in a cost effective and timely manner.

The proposed metering contestability arrangements, as outlined in the AEMC's draft Rule change, include:

- retailers must appoint a metering coordinator for each metering installation;
- all new and replacement meters must be Type 4 meters; and
- customers can only opt out of a Type 4 meter in very limited circumstances.

SA Power Networks will be dependent on the success of these arrangements to be able to offer demand tariffs to small customers. Also, the timing of introduction of our demand tariffs will now be subject to:

- the start date for contestability (currently proposed for 1 July 2017 – two years after we had planned to commence installing smart-ready meters – but possibly later, pending the Australian Energy Market Operator (**AEMO**) and the industry agreeing and developing new procedures and implementing the necessary systems changes); and/or
- retailers installing Type 4 meters prior to this date.

We also accept the AER's decision in the Preliminary Determination that all new and upgraded meters will be paid for by customers up front from 1 July 2015. This decision substantially reduces our ACS capital expenditure requirements for the 2015-20 RCP.

The AER has also rejected a significant proportion of expenditure associated with our plans to proactively replace certain meters. In particular, the AER rejected the planned replacement of certain types of electronic meters that are failing catastrophically and which are therefore not picked up in testing.[541] SA Power Networks has been notified by the meter manufacturer that these meters have reached the end of their economic lives and should be replaced. Instead, the AER has relied on historical volumes of meters replaced proactively as an indicator for future requirements. We accept this decision but note that the AER's rejection of our planned replacement program will necessarily result in an increase in our reactive replacement rate.

Our revised capital expenditure forecast includes an additional allowance for this increase, based on the dramatically increasing historical failure rates of the electronic meters noted above. We have also resubmitted part of our Original Proposal for the replacement of the three meter systems within the Holdfast Shores residential complex. The metering technology in this complex is obsolete and spare parts are no longer available. Failing individual meters will not be able to be read or replaced. If the communications system fails, none of the relevant meters will be able to be read. This Revised Proposal seeks funding for the replacement of the equipment in one of the towers, with the old equipment to be used as replacement parts for failures in the other two towers. A small investment of $44,000 (June 2015, $) for this work will eliminate a major risk.

Errors in the AER's analysis

Detailed examination of the 'opex-capex analysis' information provided by the AER in support of the decisions in the Preliminary Determination has identified a number of errors and omissions that need to be corrected. In determining the allowed capital expenditure for ACS, the AER:

- first separated proposed customer initiated expenditure (which is fully funded by customers) from the other categories of capital expenditure and determined a net capital expenditure figure; then
- removed total business overheads and input cost escalation costs from SA Power Networks' proposed expenditure; then
- made certain unit cost and volume adjustments reducing the expenditure allowances in each of the expenditure categories; and
- added these adjusted category allowances to arrive at its Preliminary Determination figure of $10.6 million (June 2015, $ million).

In reviewing these calculations, SA Power Networks has identified the following errors:

- by first separating customer initiated expenditure (which included an allocation of business overheads and input costs escalation costs) then removing total business overheads and input costs from the remaining categories, the AER has effectively twice removed the business overheads and input cost escalation costs from customer initiated expenditure;
- the AER rejected all proposed IT capital expenditure, on the basis that this expenditure was only needed to support SA Power Networks' proposed smart-ready meter program, which the AER did not approve. However, $1.3 (June 2015, $ million) of this IT capital expenditure is replacement expenditure for hand-held devices associated with 'business as usual' requirements. It is not dependent on the smart-ready meter program;
- the AER applied meter unit costs that did not include any allowance for stores on-costs, which are an overhead cost allocated via the CAM;
- the AER's substituted meter costs do not reflect the additional costs associated with bringing a new meter into our fleet and managing these meters for the term of their economic lives;
- the AER used out-of-date installation costs in some of its calculations;

[541] SA Power Networks has been notified by the meter manufacturer that these meters have reached the end of their lives and should be replaced, as noted in Attachment Q.2.

- as noted earlier, the AER reduced planned maintenance expenditure but did not include an allowance for the consequent increase in reactive meter replacements;
- the AER calculated a substitute figure for planned meter replacement and deducted this amount as an adjustment, rather than deducting the difference between the proposed figure and the substitute figure; and
- the AER omitted to apply any business overheads or input cost escalation in its approved figure of $10.6 (June 2015, $ million). This figure has then been used by the AER in its post-tax revenue model to determine revenue building blocks.

Together these errors understate the required capital allowance by $8.6 (June 2015, $ million). The AER must address these matters in its Final Determination and doing so will have minimal impact on metering charges for the remaining four regulatory years of the 2015-20 RCP.

17.2.5 Revised Proposal

In summary, our Revised Proposal largely accepts the AER's relevant decisions in its Preliminary Determination. We accept the AER's two decisions that lead to significantly less capital requirements:

- no capital for new meters is required. Rather, all new meters will be paid for by customers up front; and
- proactive replacement expenditure is based on historical volumes.

Our Revised Proposal does, however, correct the errors identified above. More information on these errors is provided in Attachment Q.1. Our revised ACS capital expenditure forecast is provided in Attachment Q.3. Attachment Q.2 describes the linkages between these models and other models discussed in this chapter to generate proposed ACS revenue and tariffs.

As the metering contestability Rule change has not been finalised at the time of lodging our Revised Proposal, SA Power Networks has forecast meter replacement capital expenditure throughout the 2015-20 RCP. Should the Rule change be finalised, as anticipated, prior to the AER making its Final Determination, we expect that the AER will not allow any capital expenditure beyond the metering contestability start date. While this may be an appropriate decision in respect of forecast meter replacement capital expenditure, it would not be appropriate in respect of SA Power Networks' IT infrastructure capital expenditure. All IT infrastructure capital expenditure included in our Revised Proposal is in respect of ongoing activities, specifically meter tariff billing, meter maintenance and meter reading.

Table 17.1 below summarises our Original Proposal for ACS capital expenditure, the AER's preliminary decision and our Revised Proposal. Our total revised forecast ACS capital expenditure is $19.2 (June 2015, $ million).

Table 17.1: ACS capital expenditure (June 2015, $ million)

	Original Proposal	Preliminary Determination	Revised Proposal
New connections	13.8	0.0	0.0
Reactive replacement	1.7	0.8	5.2
Corrective/proactive replacement	30.9	9.8	12.3
Information technology	2.6	0.0	1.7
Total ACS capital expenditure including indirect costs	**49.0**	**10.6**	**19.2**

17.3 Operating expenditure

17.3.1 Rule requirements

There is no requirement in the NER for the AER to make a constituent decision relating to ACS operating expenditure. There is also no requirement in the NER governing how ACS operating expenditure should be determined.

17.3.2 SA Power Networks' Original Proposal

In Section 21.13 of our Original Proposal, we described our proposed ACS operating expenditure. This expenditure relates to the costs of maintaining, testing and reading regulated meters.

Our proposed operating expenditure for the 2015-20 RCP included allowances for two step changes:

- the reclassification of Type 5 metering services and the relevant costs associated with metering energy data services for ACS; and
- the impact of additional reading and data costs associated with the introduction of demand tariffs for small customers in 2017/18.

SA Power Networks took a 'bottom-up' approach to determining forecast operating expenditure by forecasting volumes and determining average unit costs for each of the following services:

- meter reading;
- meter maintenance; and
- meter data management.

Volume forecasts were based on a combination of historical trend data and estimates on future plans. Unit costs were based on historical costs with annual unit step increases in meter reading and meter data management from 2017/18, reflecting the increased costs arising from moving from quarterly to monthly meter reads.

Overhead costs were directly attributed to ACS in accordance with the approved CAM.

17.3.3 AER's Preliminary Determination

In its Preliminary Determination, the AER did not accept SA Power Networks' forecast ACS operating expenditure. The AER determined a substitute amount of operating expenditure using a 'base-step-trend' approach.

The AER first determined 'base' level expenditure by reviewing SA Power Networks' average historical expenditure for the regulatory years from 2008/09 to 2012/13 and benchmarking this expenditure on a per customer per year basis with other DNSPs with a similar customer density (based on customers per kilometre of line length). The AER considered TasNetworks to be the only relevant comparator and that SA Power Networks at $8 per customer per year was 'relatively efficient' compared with TasNetworks' $26 per customer per year.

Consequently, the AER did not make any efficiency adjustment to SA Power Networks and accepted $8 per customer per year as the base for setting forecast operating expenditure.

The AER adjusted the base expenditure to include Type 5 metering maintenance (which was previously classified as a NDS in 2010-15) by adding average historic Type 5 maintenance costs to the base expenditure.

The AER did not accept SA Power Networks' proposed step increase for meter reading unit costs from 2017/18 onwards, nor did the AER include the additional cost of testing current transformer-connected (**CT**) metering installations arising from classifying Type 5 meters as ASC. The AER did not apply any step changes to the base expenditure.

The AER then trended the base forward, using customer number growth, and applied zero real price growth and productivity growth. The AER stated that having had regard to historical metering operating expenditure per customer, it believed metering operating expenditure was relatively stable for SA Power Networks and the industry as a whole.

Table 17.2 below summarises SA Power Networks' proposed expenditure and the AER's preliminary decision on allowed operating expenditure for ACS.

Table 17.2: Proposed and AER's substitute ACS operating expenditure (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Original Proposal	10.2	10.5	21.0	21.8	22.7	86.2
AER Preliminary Determination	6.9	6.9	7.0	7.0	7.1	34.9

17.3.4 SA Power Networks' response to AER Preliminary Determination

SA Power Networks notes that the AER has applied a 'base-step-trend' method in determining ACS operating expenditure for the 2015-20 RCP. This contrasts with SA Power Networks' 'bottom-up' approach to determining ACS operating expenditure.

We accept, in-principle, the AER adopting a base-step-trend method. However the AER's application of this method significantly undervalues the efficient ACS operating expenditure that SA Power Networks will require in the 2015-20 RCP.

Base expenditure

Rather than using a recent, 'revealed year' approach for the base year as it does when determining SCS operating expenditure, the AER has averaged historical operating costs in the five years from 2008/09 to 2012/13 provided in response to the Economic Benchmarking Regulatory Information Notice (**RIN**) issued by the AER in November 2013. The AER used average historical costs because it formed the view that *'operating expenditure is largely recurrent in nature'*, and *'it avoids any incentive to 'load' a single base year with expenditure going forward'*.[542]

SA Power Networks has a number of concerns with the AER's method for the establishment of our ACS base operating expenditure per customer.

Averaging expenditure over the 2008/09 to 2012/13 period as a base for determining efficient expenditure is inappropriate and inaccurate for the followings reasons:

- the accuracy of records and necessary cost allocations associated with estimated historical expenditure is low in the earliest years of the base period selected;
- in 2010/11, the first year that metering services was classified as ACS, no overheads were allocated to ACS, understating ACS costs in that year;
- the estimated expenditure prior to 2009/10 had to be re-cast using the current CAM; and
- the most recent and accurate data provided to the AER is for the 2013/14 year, and this year is not included in the AER's calculations.

The AER has then adjusted the 2008/09 to 2012/13 'raw base' expenditure by adding in Type 5 meter maintenance expenditure in these years as this expenditure was classified as NDS. Two issues arise here:

- in applying an average to these costs, the AER has undervalued the level of expenditure now required. The annual Type 5 meter maintenance expenditure during these five years has ramped up considerably from $89,000 in 2008/09 to over $1 million per annum from 2012/13 onwards as the number of Type 5 meters in service has grown during that period and has continued to grow to date; and
- the figures used in the adjustment are sourced from data sheets provided in response to a Category Analysis RIN issued by the AER in March 2014, and these figures excluded overheads and hence understate the true costs.

These issues can be remedied by calculating the base expenditure from an average of the two most recent years modelled by the AER. This would better reflect the current cost levels being faced by SA Power Networks because the earlier years are not representative of Type 5 costs. This approach has been used by SA Power Networks in our Revised Proposal. It increases the base operating expenditure per customer from the AER's assessment of $7.95 to $8.75. Alternatively, we would accept the AER using the most recent 2013/14 regulatory year as a base, as it has done when determining SCS operating expenditure.

The AER has made no further adjustments to the base operating expenditure. SA Power Networks notes that one further adjustment to base operating expenditure is required. In reviewing our Original

---

[542] AER, *Preliminary Decision: SA Power Networks determination 2015−16 to 2019−20*, April 2015, page 16-19.

Proposal for SCS operating expenditure, the AER noted and accepted our proposed negative step change of $2.2 (June 2015, $ million) per annum (equivalent to $11 (June 2015, $ million) over the 2015-20 RCP) associated with the reclassification of relevant meter data services from SCS in the 2010-15 RCP to ACS in the 2015-20 RCP.

However, in calculating ACS operating expenditure, the AER has not applied the corresponding adjustment to the base operating expenditure nor applied any step change to cater for this reclassification. This is a clear omission. SA Power Networks has included this as a further adjustment to the base operating expenditure per customer. This adds $2.61 to the adjusted base operating expenditure per customer, bringing SA Power Networks' proposed base operating expenditure per customer to $11.37 which is still only half the industry average.

Step Changes

The AER has not accepted a step change in operating expenditure associated with our proposed move to monthly manual meter reading in 2017. This move was to support our strategy to introduce cost reflective tariffs. As noted earlier, the arrangements for metering contestability have become clearer since our Original Proposal was lodged and we now have greater confidence that we can rely on interval metering rolled out by retailers under the proposed new Rules to implement our tariff strategy. Consequently we accept the AER's decision not to accept the additional operating expenditure associated with a move to monthly meter reading.

However, three further adjustments are required. We have treated the following matters as step changes, but some could equally be considered as adjustments to the base operating expenditure:

- A step change is required to reflect the increased cost of meeting compliance obligations related to testing CT metering installations. These installations must be tested every five years. Around 4000 new installations installed in the 2010-15 RCP will require testing for the first time during the 2015-20 RCP. We have assumed that the costs associated with testing CT metering installations installed prior to the 2010-15 RCP are included in the historical data. A list of relevant meters showing the installation and first testing dates, and the calculation of the average testing cost, is in Attachment Q.5;
- When meter churn occurs in the 2015-20 RCP, the meter read cost per customer for those customers remaining on manually read meters will increase. As a result, meter contract services costs will increase and additional resources will be required to manage ongoing changes with meter read routes. The following quote from the Smart Grid Smart City (**SGSC**) report supports SA Power Networks' view that:

  > *'[a]s the number of smart meters grows over time due to increases in … deployment, the cost of manually reading customer meters also increases (due to the declining numbers of [manually read] meters the same historical travel distance is still required to read a declining population of [manually read] meters). In turn the increased meter reading costs … over time further enhances the business case for smart meter infrastructure deployment.'* [543]

  SA Power Networks has included a step change for the impact of metering contestability on meter reading costs, reflecting the inefficiency experienced as we lose the economies of scale in manually read meters and the increased costs to manage read routes. This assessment, including SA Power Networks' forecast of meter churn, is set out in Attachment Q.6 and explained in Attachment Q.2. Our churn forecasts reflect the AER's preliminary decisions on reactive and corrective meter replacement forecasts, AEMO's revised forecast for new solar photovoltaic

[543] AEIF Consortium (Arup, Energeia, Frontier Economics, and Institute for Sustainable Futures - University of Technology Sydney), *Smart Grid, Smart City: Shaping Australia's Energy Future, National Cost Benefit Assessment,* July 2014, page 196.

generation uptake, and SA Power Networks' own forecasts in respect of new business and voluntary tariff uptake, service alteration volumes, and retailer initiated meter changeovers. Further discussion of the drivers of meter churn is set out in Attachment H.8; and

- SA Power Networks has previously noted that the AER's substituted unit price of $100 for a three-phase Type 6 accumulation meter is well below the lowest price available to SA Power Networks from its current suppliers. Requiring SA Power Networks to charge customers upfront for the installation of these meters effectively forces SA Power Networks to change vendors for this type of meter. However, it is expected to take around six months to add this new meter to our fleet and establish the necessary programming devices and software for all field depots. Until this is completed, we will incur a material loss on every three-phase Type 6 meter installed. SA Power Networks will also incur administrative costs to establish this new meter/vendor in our systems. We have not reflected these costs in our Revised Proposal. However, we have included the investment required to acquire and deploy the new vendor's meter programming devices in our ACS capital expenditure proposal. We have also included an ongoing operating cost for meter programming software maintenance as a step change in our ACS operating expenditure proposal. The calculations of these costs are shown and explained in our capital expenditure and operating expenditure forecast models and overview document.[544]

Trend

In applying a 'trend' to forecast future costs, the AER has used forecast customer numbers. We accept this approach but note that the AER has used forecast customer numbers that are inconsistent with (and higher than) those used for calculating historical operating costs per customer. This slightly overstates SA Power Networks' ACS operating expenditure allowance in the 2015-20 RCP. SA Power Networks' forecast customer numbers for the 2015-20 RCP reflect customer numbers consistent with those used by the AER for calculating historical operating costs per customer, adjusted for the impact of meter churn, as set out in Attachment Q.6.

The AER reasons that, on a per customer basis, expenditure levels have been relatively stable for both SA Power Networks and other DNSPs over this period and is therefore expected to be stable in the 2015-20 RCP. For this reason the AER has not applied any rate of change uplift to cater for escalation of input costs. SA Power Networks does not accept this decision. Relevant ACS metering services are equally as labour intensive as SCS services and we have therefore applied a weighted labour cost escalation factor to relevant components of our ACS expenditure forecasts, consistent with the weighting applied to relevant SCS expenditure.

Total operating expenditure

Given the errors and omissions noted above, the need for upwards adjustment to the total ACS operating expenditure is clear.

The AER's methodology for calculating SA Power Networks' benchmark ACS operating expenditure per customer effectively results in the imposition of a P_0 reduction of at least 9% compared to the latest available operating expenditure per customer (before any account is taken of step changes). This reduction is counter-intuitive and highly inappropriate given the AER's own efficiency benchmarking findings, which clearly indicate that SA Power Networks is by far the most efficient provider of metering services in Australia.

The AER has benchmarked SA Power Networks' ACS operating expenditure per customer against other DNSPs. Specifically it has compared our average cost per customer per year with TasNetworks as that

---

[544] Attachment Q.2, Q.3 and Q.6.

DNSP has a similar customer density to SA Power Networks and this is considered to be the key operating factor driving metering operating costs. On the AER's assessment, SA Power Networks' average metering services cost of $8 per customer per year is 'relatively efficient' when compared with TasNetworks' $26 per customer per year. The industry average is $20 per customer per year. Adjusting for the errors, omissions, and adjustments/step changes identified above, SA Power Networks' average metering operating cost increases to less than $13 per customer per year over the RCP. This is still well below the industry average and the TasNetworks benchmarked figure.

Given we are at the efficient frontier for metering services, it would be highly inappropriate for the AER to penalise SA Power Networks by not making the adjustments outlined above. A small error or oversight by the AER in this assessment will have a significant impact, as SA Power Networks has no inefficient margin to trim.

Accordingly, the AER must address these errors in its Final Determination, and substitute new charges to apply for the remaining four regulatory years of the RCP, including redress for revenue under-recovered in 2015/16.

17.3.5 Revised Proposal

SA Power Networks accepts, in-principle, that the base-step-trend approach can be used to determine ACS operating expenditure. SA Power Networks also accepts that the AER has rejected our proposed ACS operating expenditure associated with a proposed move to manually reading meters on a monthly basis.

However, the AER's method of determining and adjusting base expenditure has undervalued the efficient level of expenditure that SA Power Networks will incur in the 2015-20 RCP. In addition, certain errors and omissions associated with adjusting the base operating expenditure further undervalue the level of operating expenditure required.

The forecast ACS operating expenditure allowance must reflect the operating expenditure criteria, including the efficient and prudent costs of achieving the operating expenditure objective of compliance with all applicable regulatory obligations and requirements. Our Revised Proposal corrects these errors and omissions. More information on these errors is provided in Attachment Q.1. Our revised ACS operating expenditure forecast is provided in Attachment Q.6 and Attachment Q.7.

Table 17.3 below summarises our Original Proposal for ACS operating expenditure, the AER's Preliminary Determination and our Revised Proposal. Our total revised forecast ACS operating expenditure is $47.8 (June 2015, $ million).

Table 17.3: Forecast ACS operating expenditure (June 2015, $ million)

ACS operating expenditure	Original Proposal	Preliminary Determination	Revised Proposal
Total ACS operating expenditure	86.2	34.9	47.8

17.4 Revenue and Pricing

17.4.1 Rule requirements

There is no requirement in the NER for the AER to make a constituent decision relating to ACS revenue. The NER requirements governing ACS revenue and pricing are limited to making a constituent decision on the form of control mechanism for ACS. This was discussed in Section 17.1.

17.4.2 SA Power Networks' Original Proposal

In Section 29.3 of our Original Proposal, we described our proposed ACS revenue and pricing.
We adopted the building block approach in determining our revenue requirements and utilised the AER's post-tax revenue model (**PTRM**) for this calculation. The revenue building blocks comprised:

- return on capital – calculated by multiplying the MAB value by the weighted average cost of capital (**WACC**);
- return of capital – using the specific straight line depreciation calculation methodology contained in the AER's PTRM;
- operating expenditure – as discussed in Section 17.3.2 above; and
- tax liability.

Using a new Metering Pricing Model (**MPM**), we proposed seven ACS tariffs to recover this revenue. Four of these, relating to the upfront charge for meter upgrade installations, were new to ACS.

We also proposed five meter exit and transfer fees to recover operating and stranded assets costs that arise if a customer selects another meter provider. However, in the context of the emergence of metering contestability for small customers, we indicated to the AER that we were also open to considering other options which avoid the imposition of exit fees and keep SA Power Networks financially whole.

17.4.3 The AER's Preliminary Determination

In its Preliminary Determination, the AER generally accepted SA Power Networks' building block approach as the basis for establishing annual metering charges – but not the proposed values of particular building blocks.

Specifically, the AER:

- accepted the proposed MAB value;
- accepted that meter assets be depreciated over 15 years. The AER also confirmed that forecast, as opposed to actual, depreciation will apply to the roll forward of the MAB at the next RCP;
- did not accept SA Power Networks' ACS capital expenditure forecast (as noted in Section 17.2.3 above); and
- did not accept SA Power Networks' ACS operating expenditure forecast (as noted in Section 17.3.3 above).

As discussed in Section 17.1.3, the AER's Preliminary Determination approves two types of metering services charges:

- upfront capital charges for all new and upgraded meters installed from 1 July 2015; and
- annual charges comprising two components:

– a **capital component** intended to recover the costs associated with the MAB; and

– a **non-capital component** to recover ongoing operating expenditure and tax costs.

The AER has not approved any meter exit or transfer fees for regulated meters.

Table 17.4 below outlines the annual metering charges approved by the AER for the 2015-20 RCP.

Table 17.4: AER preliminary decision on SA Power Networks' annual metering charges 2015-20 (nominal)

Tariff class	Costs	2015/16	2016/17	2017/18	2018/19	2019/20
Type 1–4 'Exceptional' remotely read interval meter	Non–capital	135.07	138.51	142.05	145.67	149.38
	Capital	176.18	180.67	185.28	190.00	194.84
Type 5–6 CT connected manually read meter	Non–capital	73.52	75.40	77.32	79.29	81.32
	Capital	95.90	98.35	100.85	103.42	106.06
Type 5–6 WC manually read meter	Non–capital	8.98	9.21	9.44	9.68	9.93
	Capital	11.71	12.01	12.32	12.63	12.95

Source: AER's Preliminary Determination, Attachment 16, page 16-52

In reviewing the detailed modelling provided by the AER, we note that the AER has applied proportionate revenue reductions across each meter type and we believe this is appropriate.

Table 17.5 below outlines the upfront metering charges for new and upgraded meters that were approved by the AER for the 2015 20 RCP. The charges listed below will be adjusted by the corresponding X factor for each regulatory year, as outlined at the bottom of the table.

Table 17.5: AER preliminary decision on SA Power Networks' upfront metering charges 2015-20 (nominal)

Meter	Upfront charge ($ Dec 2014)
Type 5	
Single element	160.80
Two element	230.54
Three phase	396.43
Type 6	
Single element	100.06
Two element	254.50
Three phase	298.40

	2015/16	2016/17	2017/18	2018/19	2019/20
X factor (%)	–0.22	–0.44	–0.43	–0.44	–0.46

Source: AER's Preliminary Determination, Attachment 16, page 16-52

17.4.4 SA Power Networks' response to AER Preliminary Determination

Annual metering charges

In its Preliminary Determination, the AER has adopted a building block approach, as proposed by SA Power Networks, as a basis for establishing annual metering charges. In determining charges for 2015-20, however, the total revenue requirements are significantly lower than under our Original Proposal. The key reasons for the lower requirements, as discussed earlier in this chapter, are as follows:

- the AER did not allow funding for smart-ready interval meters;
- the AER has decided that all new and upgraded regulated Type 5 and 6 metering installations will not be capitalised, rather they will be paid for by customers up front;
- the AER determined that a lower number of meters would need to be replaced on a proactive basis; and
- the AER did not approve funding for a transition to manually reading meters on a monthly basis.

SA Power Networks accepts these decisions.

As noted earlier, however, the AER has made a number of errors in determining the ACS capital and operating expenditure allowances and these errors must be corrected in the AER's Final Determination.

We also believe that the revenue to recover the fixed costs including the tax liability and corporate overheads should be reallocated to being recovered from the capital component of the annual metering charge rather than the non-capital component as these costs are either capital related or fixed for the term of the 2015-20 RCP or both.

Upfront capital charges for new meters

In determining the upfront charges to apply to new meters, the AER decided:

- some meter unit costs proposed by SA Power Networks were higher than market rates advised by the AER's consultant, Marsden Jacobs;
- SA Power Networks' proposed non-material unit costs were reasonable; and
- to approve SA Power Networks' Type 5 meter unit costs.

The AER also determined negative X factors, weighted 60% to account for labour costs, to escalate the upfront charges which were calculated in December 2014 terms, for each of the five regulatory years of the 2015-20 RCP. SA Power Networks accepts this decision.

However, in its calculation of the tariff for upfront meter installation charges, the AER did not apply the stores on-costs and business overhead costs for Type 5 meters in accordance with SA Power Networks' CAM. SA Power Networks has corrected these errors in its revised tariff for Type 5 upfront meter installation charges. As noted elsewhere in this chapter, SA Power Networks proposes that this error be compensated by means of the A factor, when the impact can be more accurately valued.

Further, the AER did not provide for any cost recovery of corporate overheads nor any margin to SA Power Networks in the upfront meter installation charges for either Type 5 or Type 6 meters. Not allowing SA Power Networks to recover any margin in providing these services means these services are to be provided 'at cost' which is in contrast to how other regulated charges (SCS tariffs and ACS annual metering charges) are determined. These other charges are priced to recover total revenue determined using a building block approach which provides a return to the investor within the return on capital building block. This return compensates the investor for the opportunity cost of the investment.

The installation of new meters is not a capital intensive service and there is no relevant asset base on which to calculate a return. Instead, a percentage margin should be included in the upfront charges, with the percentage based on similar service industries. This position is consistent with the position taken by the AER in relation to its last Victorian determination where the AER's consultant, Impaq Consulting, noted:

> *'ACS [alternative control services] are not capital intensive and hence the application of the standard building blocks of Return of Capital and Return on Capital do not yield meaningful profit margins. However, in similar service industries profit margins of from 3% to 8% are common.'*[545]

As the metering installation service is already subject to competition,[546] and this competition will intensify materially, SA Power Networks believes a margin at the upper end of the range is most appropriate.

---

[545] Impaq Consulting, *Review of Distributors Proposed Rates in ACS Charges*, 25 May 2010, p 36 (footnotes from original omitted).

[546] There is currently no regulatory barrier to entry in respect of Type 1-4 meters. Alternative meter providers have long been able to offer regulated meter customers Type 1-4 meters.

Being forced to provide these services at 'cost', particularly when at least one meter's unit price has been set significantly below our actual cost, is inappropriate. It means SA Power Networks is in a situation where it is exposed only to risk and not to any chance of reward.

Accordingly, SA Power Networks' revised upfront charges for new meters include an 8 per cent uplift to provide an appropriate return and recover corporate overhead costs.

In 2015/16, SA Power Networks will under recover in the order of $0.5 million for these cost components. The inclusion of a non-zero A factor in the price control formula for 2016/17 onwards would provide a mechanism, to recover these costs.

17.4.5 Revised Proposal

In our Revised Proposal, we accept the AER's preliminary decisions that:

- there is no funding for smart-ready interval meters;
- all new and upgraded regulated Type 5 and 6 metering installations will not be capitalised, rather they will be paid for by customers up front;
- funding has been provided for a lower number of meters needing to be replaced on a proactive basis; and
- there is no funding for a transition to manually reading meters on a monthly basis.

We also accept the AER has not approved any meter exit fees, on the basis that DNSPs will otherwise be kept 'whole'.

We accept the AER's preliminary decision to implement a capital and non-capital metering charge for each of the three types of regulated meters. We have revised our Metering Pricing Model to determine charges in this new structure. We are also implementing billing changes to accommodate the new tariff structure.

We accept the 2015/16 annual metering charges and upfront metering charges as set out in page 16-52 of the AER's Preliminary Determination. However, for the reasons discussed earlier, we do not accept the 2016/17-19/20 charges set out in page 16-52 of the Preliminary Determination. Instead, we propose revised charges for these regulatory years, as outlined below.

We do not accept the AER's approach to setting the A factor to zero. We believe this should be left open to allow a factor to be proposed with SA Power Networks' annual pricing proposal, to account for issues outside SA Power Networks' control, particularly relating to meter churn.

We also do not accept the AER's decision to not apply the same X factors used for upfront meter charges to the annual metering charges. The AER has not explained its rationale in determining these factors, but SA Power Networks believes the same influences apply to both the installation of meters and the maintenance and reading of meters.

Tables 17.6 and 17.7 below summarise our Revised Proposal with respect to the annual metering charges and upfront charges respectively.

Table 17.6: Proposed annual metering charges (nominal)

Tariff class	Costs	AER's PD*	SA Power Networks Revised Proposal			
		2015/16	2016/17	2017/18	2018/19	2019/20
Type 1–4 'Exceptional' remotely read interval meter	Non–capital	135.07	195.45	199.48	203.59	207.78
	Capital	176.18	290.74	296.73	302.84	309.08
Type 5–6 CT connected manually read meter	Non–capital	73.52	106.39	108.58	110.82	113.10
	Capital	95.90	158.26	161.52	164.85	168.24
Type 5–6 WC manually read meter	Non–capital	8.98	12.99	13.26	13.54	13.81
	Capital	11.71	19.33	19.73	20.13	20.55

* PD = as published in the AER's Preliminary Determination, Attachment 16, page 16-52

Table 17.7: Proposed upfront capital charges for new meters (nominal)

	AER's PD*	SA Power Networks Revised Proposal			
	2015/16	2016/17	2017/18	2018/19	2019/20
Type 5 meters					
Single element	163.92	201.47	207.77	214.26	220.95
Two element	235.02	289.37	298.41	307.74	317.35
Three phase	404.13	496.52	512.04	528.04	544.54
Type 6 meters					
Single element	102.00	114.91	118.50	122.21	126.03
Two element	259.44	289.37	298.41	307.74	317.35
Three phase	304.19	341.50	352.17	363.17	374.52

* PD = Prices calculated in accordance with the AER's Preliminary Determination (that is, the AER's published December 2014 charges, escalated by CPI and adjusted by 1 - X where X= -0.22 as published in the AER's Preliminary Determination, Attachment 16, page 16-52).

More information on the calculations underpinning these proposed charges is provided in Attachment Q.8 and Attachment Q.9.

Shortened Forms

2015-20 RCP	2015-20 regulatory control period
AA1000SES	Stakeholder Engagement Standard
AS60038	Australian Standard
ABS	Australian Bureau of Statistics
ACMA	Australian Communication and Media Authority
ACS	Alternative control services
ADMS	Advanced Distribution Management System
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulatory
AMP	Asset Management Plan
ARENA	Australian Renewable Energy Agency
ARR	Annual revenue requirement
ASX	Australian Securities Exchange
ATO	Australian Taxation Office
AUGEX	Augmentation expenditure
B2B	Business-to-business
BFRA	Bushfire risk areas
BIS	BIS Shrapnel
BoM	Bureau of Meteorology
CA	Category Analysis
CA+I	Capital Appreciation Plus Income
CAM	Cost Allocation Method
CAPEX	Capital Expenditure
CAPM	Capital Asset Pricing Model
CATI	Computer assisted telephone interviewing
CATS	Consumer Administration and Transfer Solution
CBRM	Condition based risk management
CCP2	AER Consumer Challenge Panel sub-panel
CEG	Competition Economists Group
CEP	Customer Engagement Program

CESS	Capital Efficiency Sharing Scheme
CFS	Country Fire Service
CLAHs	Current limiting arcing horns
CRC	Bushfire Cooperative Research Centre
CRM	Customer Relationship Management
DAE	Deloitte Access Economics
DAPR	Distribution Annual Planning Report
DCF	Discounted Cash Flow
DCS	Direct control services
DDM	Dividend Discount Model
DEA	Data Envelopment Analysis
DER	Distributed Energy Resource
DGM	Dividend Growth Model
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DMIA	Demand management innovation allowance
DNSP	Distribution Network Services Provider
DSP	Demand Side Participation
EA	Enterprise Agreement
EAM	Enterprise Asset Management
EB	Economic Benchmarking
EBA	Enterprise Bargaining Agreement
EBSS	Efficiency Benefit Sharing Scheme
ECAPM	Empirical Capital Asset Pricing Model
EDC	Electricity Distribution Code
EDL	Energy Developments Limited
EGWWS	Electricity, Gas, Water, and Waste Services
EMCa	Energy Market Consultants Associates
EMG	Executive Management Group
ENA	Energy Networks Association
ERP	Enterprise Resource Planning System
ESC	Essential Services Commission
ESCoSA	Essential Services Commission of South Australia

ETC	Estimated Tax Cost
EWPs	Elevated work platforms
F&A	Framework and Approach
FF3F	Fama French Three Factor Model
FOM	SA Power Networks' Future Operating Model
FRC	Full retail contestability
FTE	Full time equivalent
GFC	Global Financial Crisis
GFN	Ground fault neutralising technology
GrN	Government radio network
GSL	Guaranteed Service Levels
GWh	Gigawatt hours
HBRA	High bushfire risk areas
IAP2	International Association of Public Participation
IEEE	Institute of Electrical and Electronics Engineers
IPART	Independent Pricing and Regulatory Tribunal (NSW)
IT	Information technology
ITC	Information technology and communications
IVMS	In Vehicle Management Systems
Jacobs	Jacobs Engineering Group (formerly SKM)
KI	Kangaroo Island
LGA	Local Government Association
LR	Long Rural
LRMC	Long run marginal cost
MAB	Meter asset base
MAC	Motor Accident Commission
MAIFI	Momentary Average Interruption Frequency Index
MC	Metering Coordinator
MED	Major Event Days
MFS	Maloney Field Services
MPM	Metering Pricing Model
MRP	Market Risk Premium

MRV	Maintenance risk value
MSATS	Market Settlement and Transfer Solutions
MTFP	Multilateral Total Factor Productivity
MVDFM	Multi variable defect forecasting model
MW	Megawatts
NBFRA	Non bushfire risk areas
NDS	Negotiated distribution services
NDSC	Negotiated distribution service criteria
NECF	National Energy Customer Framework
NEFR	National Energy Forecast Report
NEM	National Electricity Market
NEO	National Electricity Objective
NEL	National Electricity Law
NERL	National Energy Retail Law
NGR	National Gas Rules
NMI	National Meter Identifier
NMS	Network Management System
NOC	Network Operations Centre
NPV	Net Present Value
NTF	Nelson Taylor Fox
O&M	Operations and Maintenance
OMS	Outage Management System
OPEX	Operating Expenditure
OTR	Office of the Technical Regulator
ORP	Original Regulatory Proposal
PBST	Powerline Bushfire Safety Taskforce
PLEC	Power Line Environment Committee
PoE	Probability of Exceedance
PPI	Producer Price Indices
PPM	Portfolio Project Management
PQ	Power quality
PSC	Power Systems Consulting

PTRM	Post Tax Revenue Model
PV	Photovoltaic
QoS	Quality of Supply
RAB	Regulated Asset Base
RAGs	Rod air gaps
REPEX	Replacement expenditure
RFM	Roll Forward Model
RIT-D	Regulatory Investment Test-Distribution
RIN	Regulatory Information Notice
RMU	Ring main unit
RPP	Revenue and Pricing Principles
RRP	Revised Regulatory Proposal
RTU	Remote Terminal Units
SACOSS	SA Council of Social Services
SAGRN	SA Government Radio Network
SAPN	SA Power Networks
SAPN CCP	SA Power Networks' Customer Consultative Panel
SAUR	Shared asset unregulated revenue
SCADA	Supervisory Control and Data Acquisition
SCER	Standing Council Energy & Resource
SCS	Standard Control Services
SEM	Submission Expenditure Model
SL-CAPM	Sharpe-Lintner Capital Asset Pricing Model
SORI	Statement of Regulatory Intent
SR	Short Rural
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan
STPIS	Service Target Performance Incentive Scheme
SSF	Service Standards Framework
SSIS	Small Scale Incentive Scheme
SWE	Severe weather events
TEC	Total Environment Centre
TNOC	Telecommunications Network Operations Centre

TNSP	Transmission Network Service Providers
Tribunal	Australian Competition Tribunal
TSS	Tariff Structures Statement
TSW	Trade Skilled Workers
UK	United Kingdom
URD	Underground residential development
US	United States
USAIDI	Unplanned System Average Interruption Duration Index
USAIFI	Unplanned System Average Interruption Frequency Index
VBRC	Victorian Bushfire Royal Commission
VCR	Value of Customer Reliability
VHF	Very High Frequency
WACC	Weighted Average Cost of Capital
WARL	Weighted Average Remaining Lives
WHS	Work health and safety
Willis	Willis Risk Services
WPI	Wage Price Index
WTP	Willingness to Pay

Attachments

A.1	SA Power Networks: Revised Proposal Confidentiality Claim
A.2	SA Power Networks: Revised Proposal Director's Certification
C.1	Banarra Stakeholder Engagement Assessment-Final Gap Analysis Report
C.2	The NTF Group Report on SACOSS Consumer Research
C.3	The NTF Group Report on Business SA Research
C.4	The NTF Group Report on CCP2 comments on Willingness to Pay Research
C.5	The NTF Group Response to SACOSS
C.6	The NTF Group Report on Oakley Greenwood Peer Review
C.7	The NTF Group Review of AER Response
G.1	SA Power Networks Kangaroo Island submarine cable - additional information
G.1b	Kangaroo Island submarine cable EMCa – SAPN review
G.2	SA Power Networks Bushfire mitigation supporting evidence
G.3	SA Power Networks Risk Spatial SA Power Networks Bushfire Risk Report
G.4	SA Power Networks Metered mains supporting evidence
G.5	SA Power Networks Protection compliance backup protection
G.6	SA Power Networks Reliability - Hardening the network
G.7	SA Power Networks Reliability - Low reliability feeders
6.8	SA Power Networks Reliability - Poorly served communities
G.9	SA Power Networks Reliability - Micro-grid trial
G.10a	DGA: Revised ADMS and ZSS
G.10b	DGA: Revised ADMS and ZSS Cost benefit analysis
G.12	SA Power Networks Voltage Monitoring in the LV network
G.13	SA Power Networks KPMG IT Review
G.14	SA Power Networks IT Resourcing and Deliverability
G.15	SA Power Networks IT Field Force Mobility Business Case
G.16	SA Power Networks IT Enterprise Asset Management Business Case
G.17	SA Power Networks IT Data Centre Business Case
G.18	SA Power Networks IT Enterprise Information Security Business Case
G.19	SA Power Networks IT RIN Reporting Business Case
G.20	SA Power Networks IT SAP Foundation Business Case

G.21	SA Power Networks IT CISOV Replacement Business Case
G.22	SA Power Networks IT EAM and RIN Reporting Paper
G.23	SA Power Networks IT PPM Business Case
G.24	SA Power Networks IT Benefits
G.25	SA Power Networks TNOC Business Case
G.27	SA Power Networks Revised SCS CAPEX SEM
H.1	Frontier Economics: Review of AER's Preliminary Decision on Labour Escalation Rates
H.2	NERA: Allowed Rate of Change due to Expected Inflation in Labour Costs
H.3	SA Power Networks Skills Shortages in SA Power Networks
H.4	BIS Shrapnel: Utilities Sector Wage Forecasts to 2019/20
H.5	SA Power Networks Opex Step Change – No Access Poles
H.6	SA Power Networks Bushfire Safety – Opex Inspection Cycle Step Change
H.6a	SA Power Networks Bushfire Safety – Opex Step Change Inspect Cycle – MVI Model Appendix
H.7	SA Power Networks Distribution Network Pricing Rules
H.7a	SA Power Networks Distribution Network Pricing Rules Cost Estimations Appendix
H.8	SA Power Networks Competition in Metering Rule Change
H.8a	SA Power Networks Competition in metering rule change Cost Estimations Appendix
H.9	SA Power Networks Radio Network Business Case
H.10	GHD: Vegetation Management Bushfire Program
H.11	NERA: Funding Projects that Provide Customer Benefits
H.12	SA Power Networks Revised SCS OPEX SEM
K.1	SA Power Networks Shared Assets Model
L.1	SA Power Networks Roll Forward Model - SCS
L.2	SA Power Networks Roll Forward Model - ACS
L.3	SA Power Networks Roll Forward Model Schedules
M.1	RBA: Speech
M.2	NERA: Review of the Literature in Support of the Sharpe-Lintner CAPM; the Black CAPM and the Fama-French Three-Factor Model
M.3	SFG: The foundation model approach of the Australian Energy Regulator to estimating the cost of equity
M.4	SFG: The required return on equity for the benchmark efficient entity
M.5	NERA: Historical Estimates of the Market Risk Premium

M.6	NERA: Empirical Performance of the Sharpe-Lintner and Black CAPM
M.7	SFG: Beta and the Black Capital Asset Pricing Model
M.8	SFG: Using the Fama-French model to estimate the required return on equity
M.9	SFG: Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network
M.10	GRANT SAMUEL: Letter from Grant Samuel & Associates Pty Limited to the Directors of Transgrid
M.11	INCENTA: Further update on the required return on equity from Independent expert reports
M.12	FRONTIER: Key issues in estimating the return on equity for the benchmark efficient entity
M.13	FRONTIER: Review of the AER's conceptual analysis for equity beta
M.14	NERA: The Cost of Equity: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, and for Jemena Gas Networks
M.15	NERA: Further Assessment of the Historical MRP: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors
M.16	MALKO: Dr Robert Malko Statement
M.17	KNECHT: Ronald L. Knecht Statement
M.18	SFG: Updated estimate of the required return on equity, Report for SA Power Networks
M.19	SFG: Estimating Gamma for Regulatory Purposes
M.20	M20_NERA: Estimating distribution and redemption rates from taxation statistics
M.21	FRONTIER: An appropriate regulatory estimate of gamma
M.22	NERA: Estimating Distribution and Redemption Rates: Response to the AER's Final Decision for the NSW and ACT Electricity Distributors, and for Jemena Gas Networks
M.23	SFG: Return on debt transition arrangements under the NGR and NER, Draft report for Jemena Gas Networks, Jemena Electricity Networks and United Energy
M.24	CEG: Critique of the AER's JGN draft decision on the cost of debt
M.25	SCHLOGL: The AER's JGN draft decision on the cost of debt – a review of the critique by the CEG
M.26	CEG: Transition to the trailing average rate of return on debt, Assessment and calculations for SAPN
M.27	CEG: Extrapolation of the Bloomberg curve to 10 years
M.28	CEG: Measuring expected inflation for the PTRM
M.29	FRONTIER: Cost of equity estimates over time
M.30	WACC: Supporting Documentation
N.1	Houston Kemp: Report on Depreciation

N.2	SA Power Networks Regulatory Asset Register - SCS
N.3	SA Power Networks SAPN Regulatory Asset Register - ACS
P.1	SA Power Networks Revised PTRM - SCS
Q.1	SA Power Networks Revised ACS Opex-capex analysis
Q.2	SA Power Networks Modelling overview - ACS
Q.3	SA Power Networks Revised ACS capex forecast model
Q.4	SA Power Networks Revised ACS capex submission expenditure model
Q.5	SA Power Networks CT Testing schedule
Q.6	SA Power Networks Revised ACS opex forecast model
Q.7	SA Power Networks Revised ACS Opex - submission expenditure model
Q.8	SA Power Networks Revised ACS Metering Pricing Model
Q.9	SA Power Networks Revised ACS PTRM