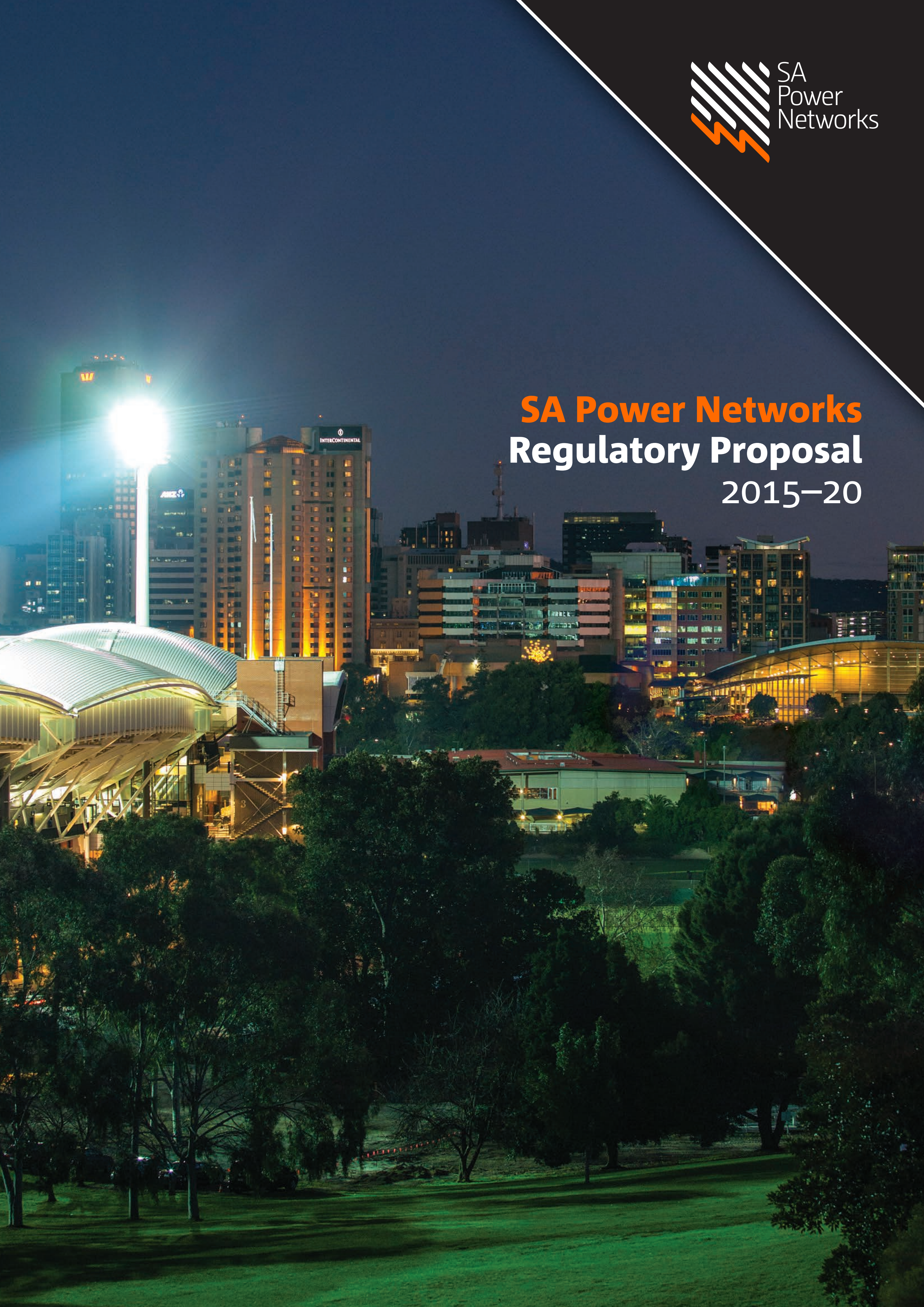


SA Power Networks Regulatory Proposal 2015–20

Foreword from the CEO

At SA Power Networks we recognise that electricity is the lifeblood of our community. We are one of our State's major essential service providers, and we understand the responsibility we hold in delivery of our services for all South Australians.

We have a proud history of providing cost efficient, safe and reliable electricity supply for our customers. Recent benchmarking data gathered from across the industry by our Regulator shows that in addition to our network being one of the most reliable, we are also the most efficient distributor. But we know we cannot rest on the achievements of the past, as we are in a time of unprecedented change in the way customers use the distribution network. Customer expectations are changing as customers embrace new electricity supply technologies and service options becoming available to them.

Balancing current and future customer needs underpins the discussion, thinking and planning that has gone into our 2015–20 Regulatory Proposal.

In preparing our Proposal, we have conducted an extensive and unprecedented level of consultation with our customers and interested stakeholders. I thank the many thousands of people across the State who participated in workshops, one-on-one meetings, surveys and various research projects.

Never before have we had the benefit of this quality of information on the things that customers value. We have used these valuable insights to improve the scope and balance of our proposed investments in the network and the range of services to our customers and the South Australian community.

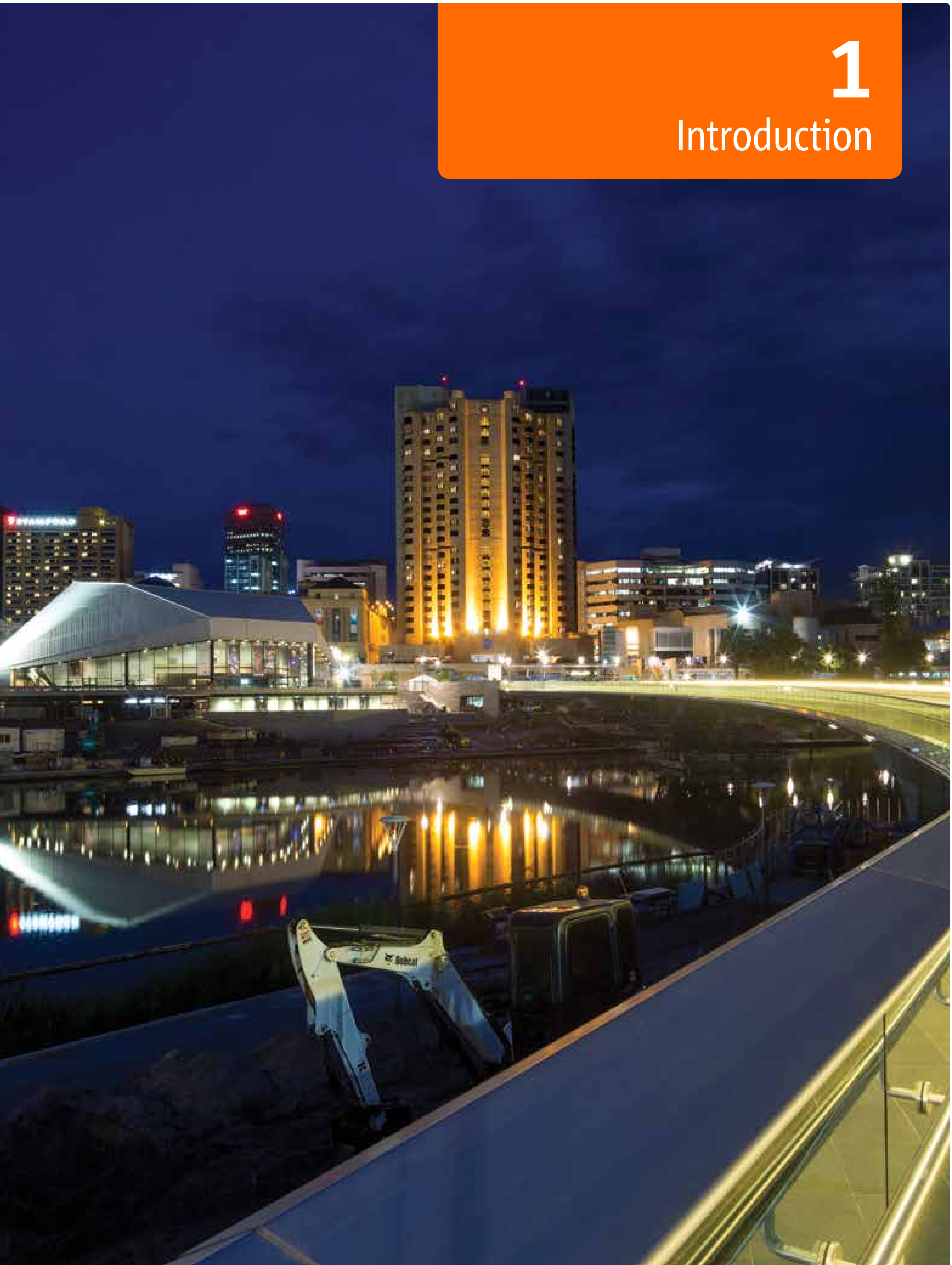
While our consultation with the community has clearly shown support for appropriate investment, we have also been very mindful of community concern regarding electricity prices. Our network charges are now about a third of the average residential electricity bill. This Proposal will ensure that increases in distribution charges for the next five years stay below CPI.

Through this Proposal we will continue to provide an efficient, reliable and safe distribution network for all South Australians. We will also be well placed to respond to our customers' evolving needs and expectations in a changing electricity market.

Rob Stobbe
Chief Executive Officer
SA Power Networks

Contents

1
Introduction



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This document and its principal attachments comprise SA Power Networks' Regulatory Proposal (**the Proposal**) to the Australian Energy Regulator (**AER**) for the regulatory control period (**RCP**), 1 July 2015 to 30 June 2020. It sets out the revenue required to manage the network in a safe, reliable and efficient manner for our customers and the community. The Proposal is supported by the following accompanying documents:

- an easy to read 'Overview Paper' that has been developed in line with clause 6.8.2(c1) of the National Electricity Rules (**NER**);
- copies of SA Power Networks' documentation supporting the Proposal and principal attachments (including the information required by the AER's Expenditure Forecast Assessment Guidelines) provided on an electronic storage device; and
- responses to a Reset Regulatory Information Notice (**RIN**).

This Proposal and its principal attachments were prepared specifically for the current regulatory process and are current as at the time of lodgement.

Information contained on the electronic device, although forming part of the 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

Regulatory context

As a monopoly service provider, SA Power Networks is subject to comprehensive regulation that is designed to ensure appropriate outcomes for customers, the South Australian community and investors. SA Power Networks requires a fair commercial return to enable it to deliver an appropriate level of network reliability, safety and customer service in an efficient and sustainable manner.

The economic regulation of SA Power Networks is undertaken by the AER. In undertaking this economic regulation role, the AER is required to do so in a manner that will or is likely to contribute to the achievement of the National Electricity Objective (**NEO**) as stated in Section 7 of the National Electricity Law (**NEL**).

The objective of this Law 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:

- price, quality, safety, reliability and security of supply of electricity; and
- the reliability, safety and security of the national electricity system.

The state-based regulator, the Essential Services Commission of South Australia (**ESCoSA**), retains responsibility for setting service levels, while the Office of the Technical Regulator (**OTR**) is responsible for safety and technical regulation in South Australia.

The AER has decided to apply a revenue cap form of control to our distribution standard control services in the 2015–20 RCP and has put in place incentive arrangements to encourage SA Power Networks to achieve efficiency gains, further investigate demand management opportunities, and improve service performance to customers over the RCP.

The AER is required to ensure that pricing outcomes, and the revenues on which they are predicated, are sufficient to enable SA Power Networks to undertake the capital and operating work programs required to deliver the service levels as defined by ESCoSA, comply with all applicable regulatory obligations and requirements and maintain the safety of the distribution system. The allowed pricing outcomes must also provide for a fair commercial return for the business.

Since the 2010–15 regulatory determination (the **2010 determination**) there has been significant regulatory change, articulated in Chapter 5.

In addition, at the time of writing, a number of important NER change consultations remain in progress, including those aimed at expanding competition in metering and related services, and changes to distribution network pricing arrangements. The Proposal generally reflects our best assessment of the impact of open NER change processes, but changes to our regulatory arrangements that are determined subsequent to the submission of this Proposal may require further consideration during the AER's determination process as appropriate.

Some components of the regulatory arrangements that are to apply in the 2015–20 RCP have already been the subject of consultation and final decision, including the ESCoSA Service Standards Framework (**SSF**) and the AER's 'Better Regulation' Guidelines. Also, in April 2014, the AER released its 'Framework and Approach' paper (**F&A**) for SA Power Networks. The F&A, among other things, defines the revenue control mechanism to apply in the 2015–20 RCP, the AER's proposed approach to the classification of distribution services and the specific application of regulatory incentive schemes in the 2015–20 RCP.

Further information on the Guidelines and F&A can be found at **aer.gov.au** and the final SSF can be found at **escosa.sa.gov.au**.

1.2

Structure of this document

We appreciate that the readers of this document will range from regulatory experts and well informed stakeholders through to our customers who may have had little previous knowledge of SA Power Networks and our role in the National Electricity Market (**NEM**).

In addition to this detailed Proposal we have produced a separate plain English overview document which summarises the Proposal and is available on our **TalkingPower.com.au** website. We have sought to minimise 'industry jargon' contained in the Proposal and have included a list of shortened forms at the end of the document to help explain specific terms used.

Throughout this document, the reader is also directed to a number of important supporting documents and third party reports and in which attachments those reports are located. Table 1.1 provides a breakdown and overview of each individual chapter contained within this Proposal.

Table 1.1 Chapters of the Proposal

Chapter	Title	Context
2	Executive summary	An overview of the Regulatory Proposal, its objectives and conclusions.
3	Business overview	A description of our business in terms of our role, the network, our customers, our organisation and our governance arrangements.
4	Our track record	A summary of our balanced achievements to date, including reliability, efficiency, service and safety.
5	Our operating environment	Current operating environment challenges and the new operating environment challenges that will apply for the 2015–20 RCP.
6	Our customer engagement	An overview of our customer engagement principles, process, methods, reach, effectiveness and findings.
7	Regulatory Proposal key inputs	The key inputs that have been used in preparing our Regulatory Proposal.
8	Proposal overview	A high level summary of our key service areas, programs of work, and proposed expenditures.
9	Keeping the power on for South Australians	For each of these key service areas for South Australian customers, we provide a discussion of our regulated obligations, key operational issues, customer feedback, feedback evaluations, programs of work, proposed expenditures and associated benefits.
10	Responding to severe weather events	
11	Safety for the community	
12	Growing the network in line with South Australia's needs	
13	Ensuring power supply meets voltage and quality standards	
14	Serving customers now and in the future	
15	Fitting in with our streets and communities	
16	Capabilities to meet our challenges	
17	Service-price trade-off	An assessment of the overall value of the combined programs of work.
18	Classification of Services and Negotiating Framework	Describes the proposed classification of distribution services for the 2015–20 RCP.
19	Control Mechanisms	Describes the control mechanisms that will apply to Standard Control Services (**SCS**) and Alternative Control Services (**ACS**).
20	Forecast capital expenditure	Details the capital expenditure forecast for the 2015–20 RCP.

Chapter	Title	Context
21	Forecast operating expenditure	Details the operating expenditure forecast for the 2015–20 RCP.
22	Pass-through events	An explanation of proposed pass through events and their triggers.
23	Incentive schemes	An explanation of the incentive schemes that will apply for the 2015–20 RCP.
24	Shared assets	An explanation of the application of the Shared Assets Guideline to SA Power Networks for the 2015–20 RCP.
25	Regulated asset base	The methodology that will be applied in calculating the Regulated Asset Base for SCS and ACS.
26	Weighted average cost of capital	Sets out the Rate of Return that we consider should be applied in SA Power Networks' distribution determination.
27	Depreciation	Presents the forecast of depreciation for the current and future regulatory control periods.
28	Estimated cost of corporate income tax	Sets out estimated corporate tax costs for the 2015–20 RCP.
29	Revenue and pricing	Summarises the total revenues that will be recovered through our tariffs, and the associated network pricing impacts on customers.
30	Shortened forms	An explanation of specific terms and acronyms.
31	Proposal attachments	Principal attachments in support of this Proposal.

1.3

Determination timeframes and feedback opportunities

This Proposal outlines SA Power Networks' work programs, expenditures, regulatory arrangements, and rate of return, as well as the allowable distribution revenue for the 2015–20 RCP.

Following an assessment of the Proposal and submissions received from interested parties, the AER will make a first determination by 30 April 2015.

Transitional arrangements are currently in place as a consequence of NER changes in 2012 which extend the usual determination timeframes. Thus, although SA Power Networks' next RCP will still commence on 1 July 2015, the AER will continue the determination process as required by clause 11.60.4 of the NER.

SA Power Networks and other interested parties will then have the opportunity to make further submissions on the first determination to the AER by 2 July 2015. Subsequently, the AER will publish a substitute determination by 31 October 2015 that will take effect from 1 July 2016.

Any differences between the first determination and the substitute determination that affect the allowable revenues in the 2015/16 regulatory year will be addressed by means of a revenue 'true-up' at 1 July 2016.

Throughout the determination process the AER will consult with interested parties and take their views into account.

Further information on the AER's approach to SA Power Networks — Determination 2015–20 can be found at the AER website: **http://www.aer.gov.au/node/20941.**

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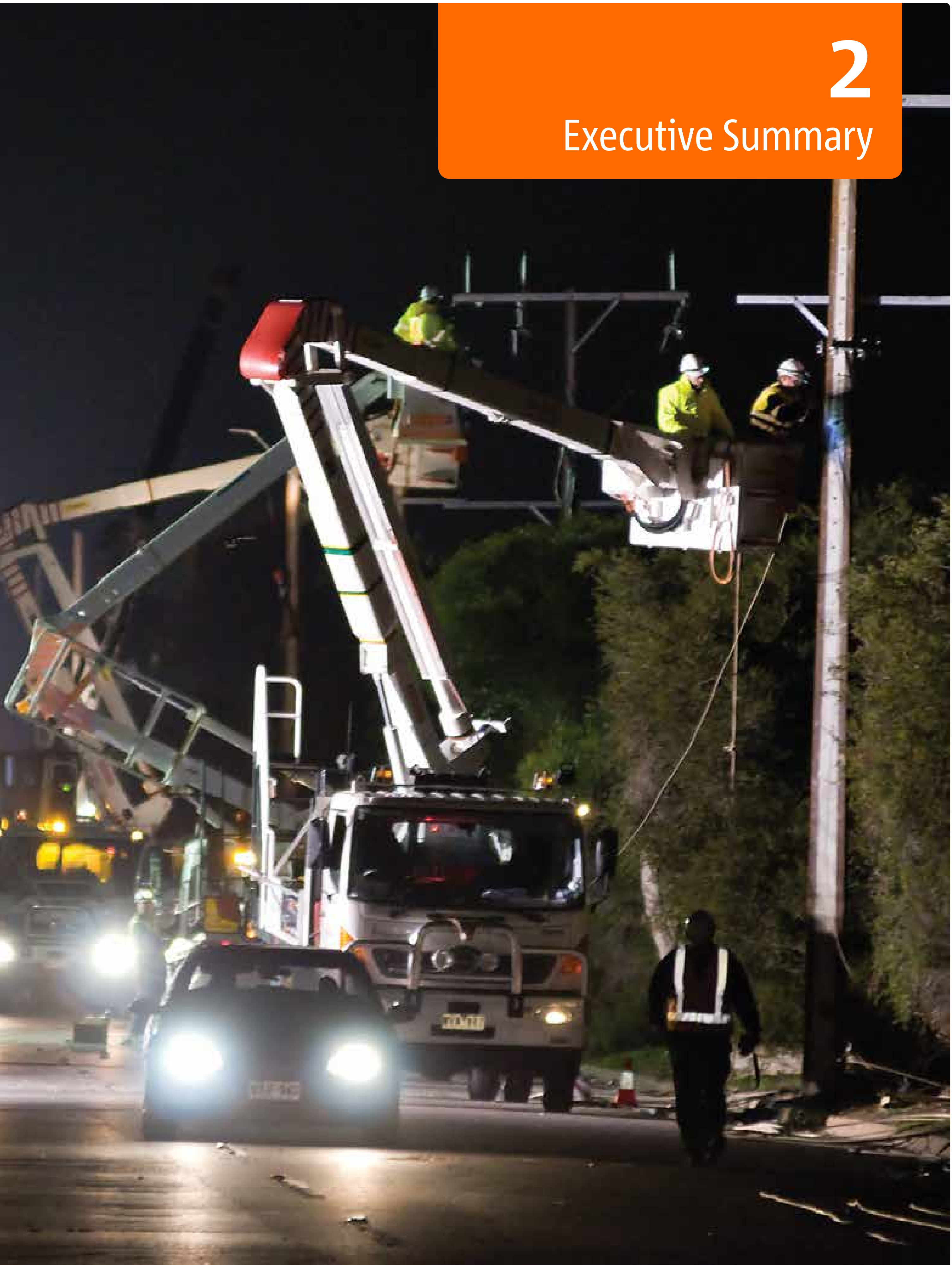
2
Executive Summary



2

SA Power Networks has always valued its key role in ensuring our distribution network supports the needs and development of South Australia and its communities. We have proudly served South Australians for almost 70 years, initially as part of the Electricity Trust of South Australia, and then as a stand-alone distribution business established in the late 1990s when the electricity supply industry was transformed by a new regulatory framework.

2.1

Strong performance as an essential service provider in South Australia

As the South Australian Distribution Network Service Provider (**DNSP**) our primary responsibility is planning, building, operating and maintaining the South Australian electricity distribution network — a strategic community asset and core component of the State's energy infrastructure. We do this in a safe, reliable, efficient and prudent manner.

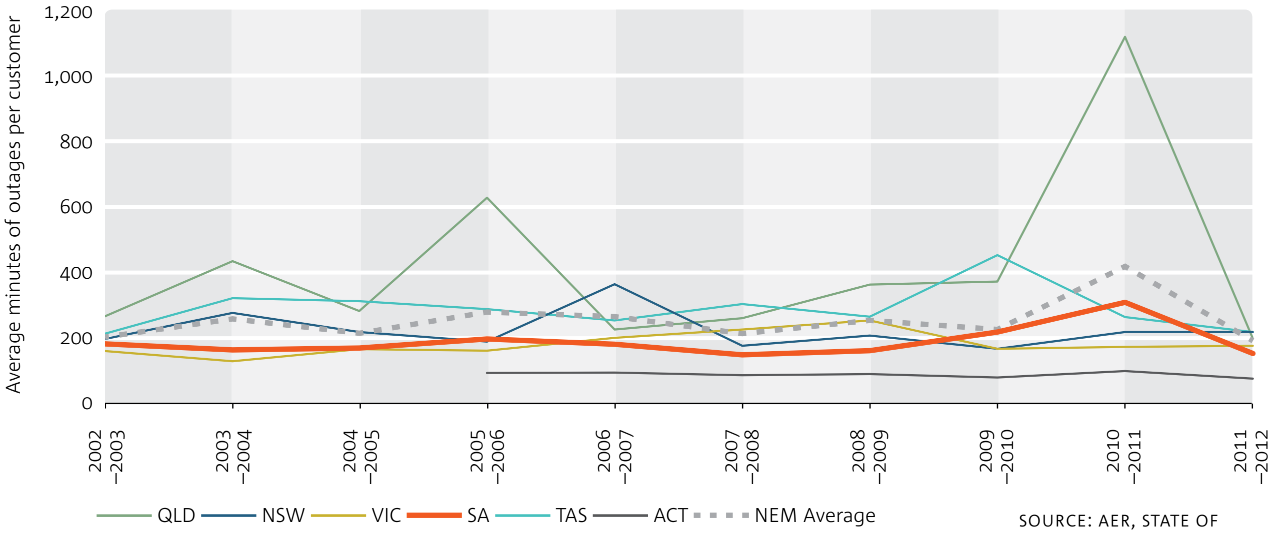
SA Power Networks has consistently provided a strong, balanced performance across all key dimensions of our business:

- our network is one of the most reliable in Australia;
- our customer service performance consistently meets all regulated standards;
- we have strong and productive stakeholder relationships;
- our workplace sets a safety performance benchmark in our sector;
- we meet all environmental obligations and are successfully reducing the organisation's environmental footprint;
- we maintain a positive reputation in South Australia;
- we have reduced our share of total electricity bills;
- we proactively manage key business risks and provide acceptable returns to our owners;
- we continue to be a major employer in South Australia; and
- we are the most cost efficient distribution business in the National Electricity Market (**NEM**).

SA Power Networks' reliability performance is often cited as a key benchmark of our operational performance. As shown in Figure 2.1, the South Australian distribution network's reliability performance has remained better than the NEM average for many years, and 88% of our customers say they are satisfied or very satisfied with their current reliability.

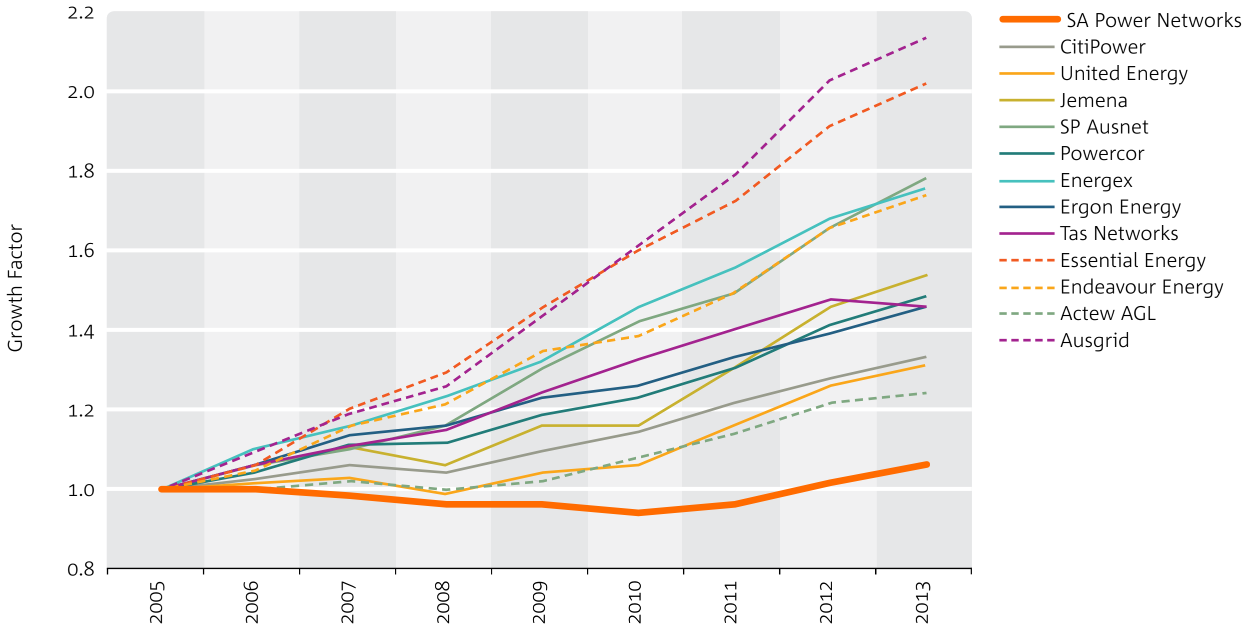
This reliability performance has been achieved whilst having tightly constrained capital investment in earlier years and the increased network investment required in the current 2010–15 RCP. Figure 2.2 shows the relative growth in real Regulated Asset Base (**RAB**) for NEM DNSPs since 2005 (which is the earliest year of data published by the AER for benchmarking purposes). SA Power Networks' relative RAB growth has been the lowest in the NEM, and provides assurance that SA Power Networks' investment in network infrastructure has been prudent and measured.

Figure 2.1: Australia-wide distribution network performance — system reliability



SOURCE: AER, STATE OF THE ENERGY MARKET 2013

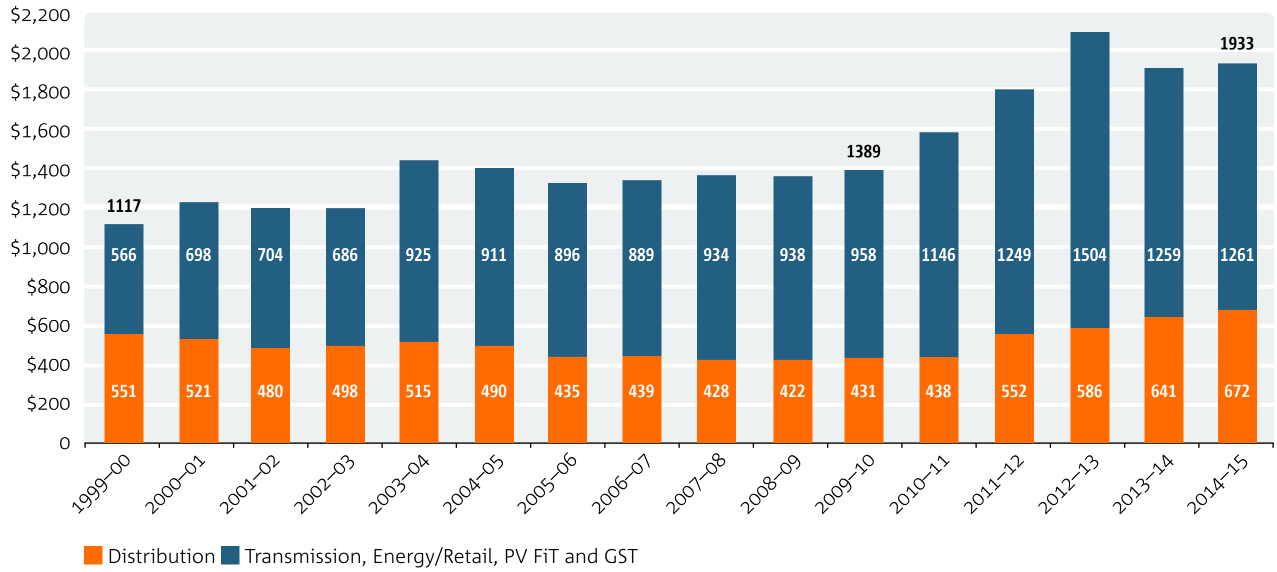
Figure 2.2: Real RAB growth since 2005— NEM DNSPs



SOURCE: SA POWER NETWORKS ANALYSIS, BASED ON AUSTRALIAN ENERGY REGULATOR BENCHMARKING DATA 2014

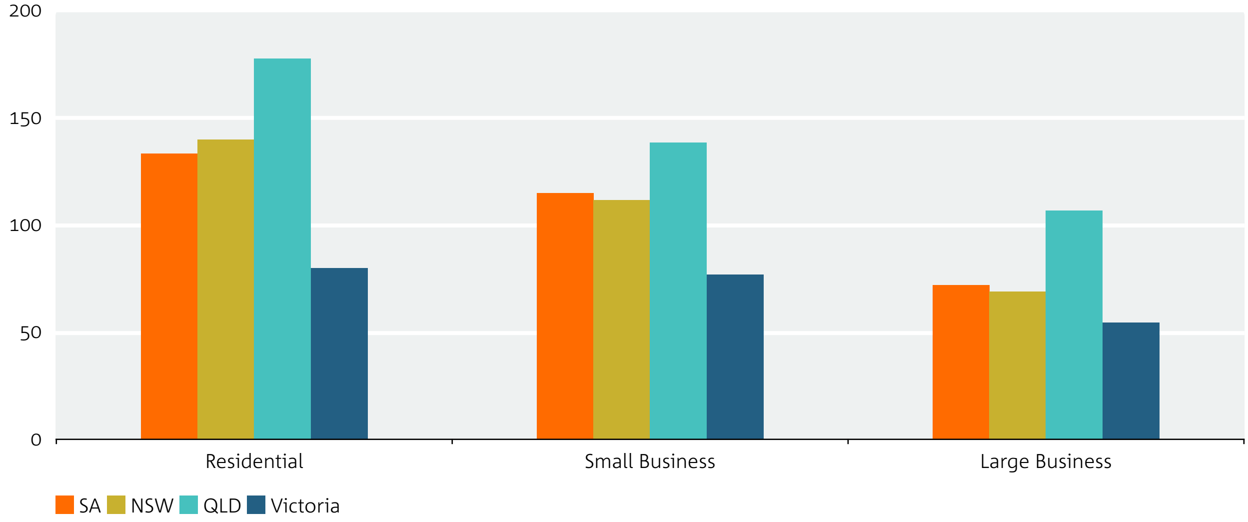
In terms of price, we have managed to keep distribution network prices for residential customers relatively stable in real terms. Figure 2.3 shows the historical trend in electricity costs since 1999/00 for the average residential customer (5 MWh per annum). Our share of the average electricity bill is now around one third, down from almost 50% in 1999/00. Over this 15 year period, SA Power Networks' distribution costs for the average 5MWh residential electricity customer account for only 15% of the increase in total electricity bills ($121 of the $816 increase).

Figure 2.3: Change in average 5MWh residential electricity customer annual electricity bill components (1999–2015) (All values in 2014/15 $)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Figure 2.4: Comparison of average Australian distribution prices (July 2014, excl GST) (All values in 2014–15 $/MWh)

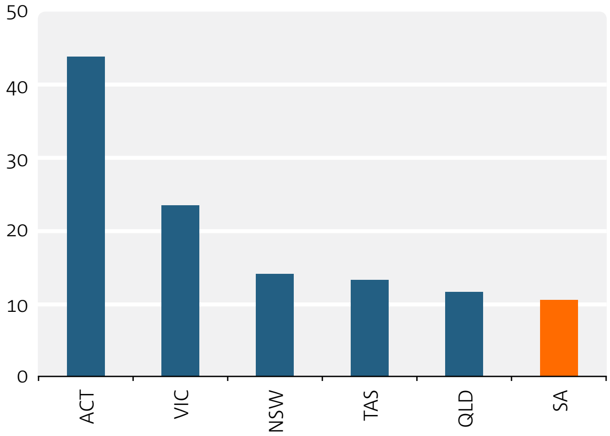


SOURCE: SA POWER NETWORKS ANALYSIS 2014

Interstate tariff comparisons show that SA Power Networks' distribution prices for each of the principal customer segments (residential, small business and large business) remain competitive with those of other mainland states. Figure 2.4 shows the typical prices paid in July 2014 for distribution services (including metering) in Queensland, New South Wales, Victoria and South Australia. A simple average of the tariffs from the distributors operating in each of these states has been used, enabling state-wide distribution price outcomes to be compared.

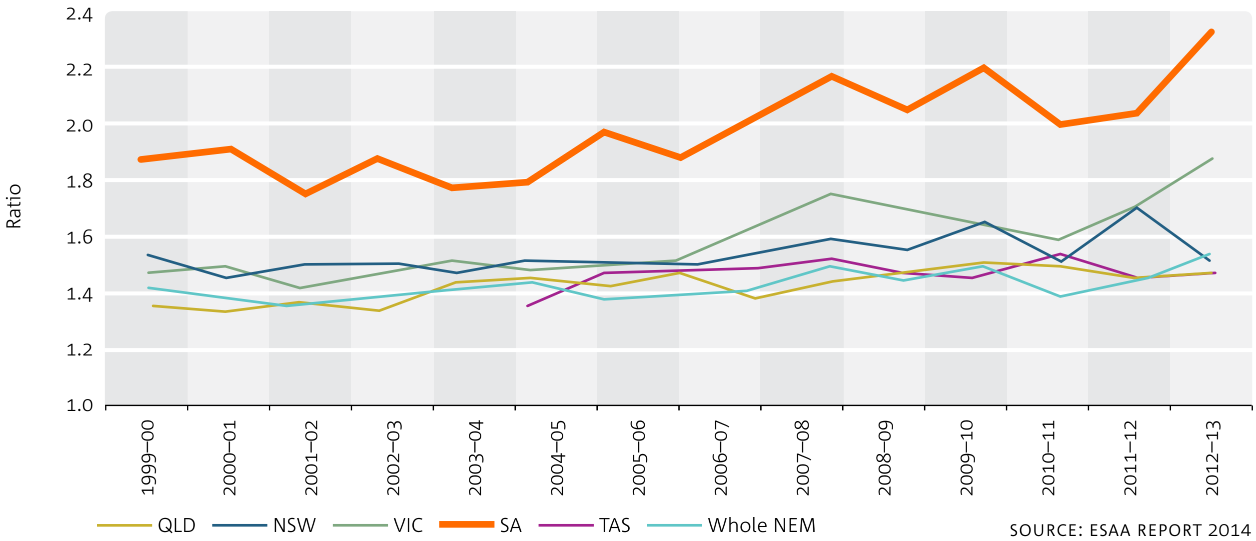
This pricing outcome represents significant achievement, considering the unique environmental circumstances faced by SA Power Networks. Our customer base has the lowest customer density in the NEM (refer Figure 2.5). High air conditioning penetration and a summer climate characterised by severe heatwaves means that South Australian demand is also the peakiest in Australia and among the peakiest in the world. Figure 2.6 shows the ratio of peak demand to average demand for the NEM states.

Figure 2.5: Comparison of customer densities for NEM states (customers per route km of line length)



SOURCE: SA POWER NETWORKS ANALYSIS, BASED ON 2012/13 ECONOMIC BENCHMARKING REGULATORY INFORMATION NOTICE (**RIN**) DATA, AER 2014

Figure 2.6: Comparison of ratios of peak demand to average demand in the NEM



SOURCE: ESAA REPORT 2014

Both of these environmental factors contribute to higher DNSP costs per customer, all other things being equal, since both result in more network assets being required to service the same number of customers.

Our continued focus on providing services prudently and efficiently has allowed the delivery of ongoing good reliability performance together with reasonable pricing outcomes, despite recent investment increases and unfavourable environmental circumstances as described above.

This is consistent with SA Power Networks' long record of efficient performance. Recent benchmarking analysis based on the AER's preferred productivity models and AER-published data for NEM DNSPs shows that on a state and individual DNSP basis, SA Power Networks is the most efficient DNSP in the NEM (refer Figure 2.7).

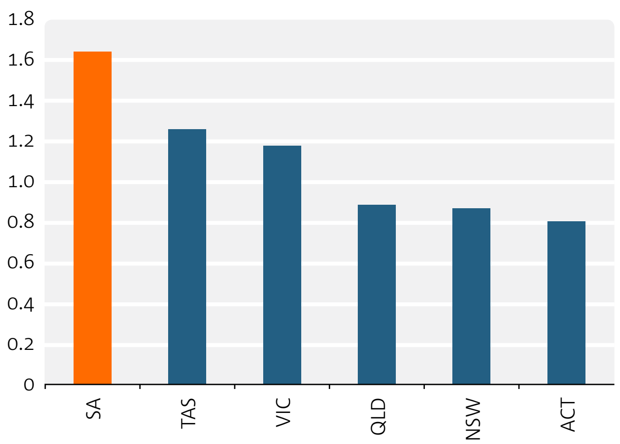
In summary, SA Power Networks is a high-performing DNSP. We will continue to invest in our network, people and systems to ensure we stay at the forefront of efficient capabilities and this will underpin our performance in the coming years, a period of significant change for our customers and industry.

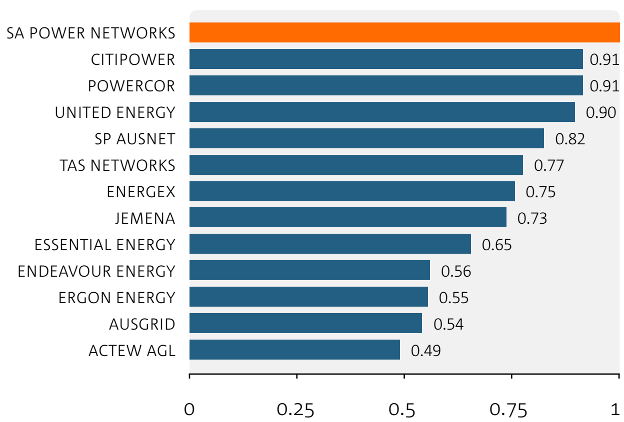
2.2

Energy customers and the energy industry are transforming

"... We are on the cusp of a further fundamental shift in the way electricity is produced and consumed ... we are seeing a shift to a new paradigm in which the primary service provided by the electricity network will be a platform for the trade of electricity services between suppliers and customers—both large and small. The convergence of communications and energy transport and the uptake of smart meters and other household devices brings opportunities for innovation and competition. It has become feasible for small customers to be actively integrated into the electricity market." — Speech by the outgoing Chair of the AER, Mr Andrew Reeves, to ENA Regulatory Forum, Brisbane, 6 August 2014.

Figure 2.7: Multilateral Total Factor Productivity 2013 — jurisdictional and DNSP comparisons





SOURCE: HUEGIN ANALYSIS, BASED ON AER 2013 PREFERRED SPECIFICATION PRODUCTIVITY MODEL ADJUSTED FOR CUSTOMER DENSITY, AND AER ECONOMIC BENCHMARKING DATA MAY 2014

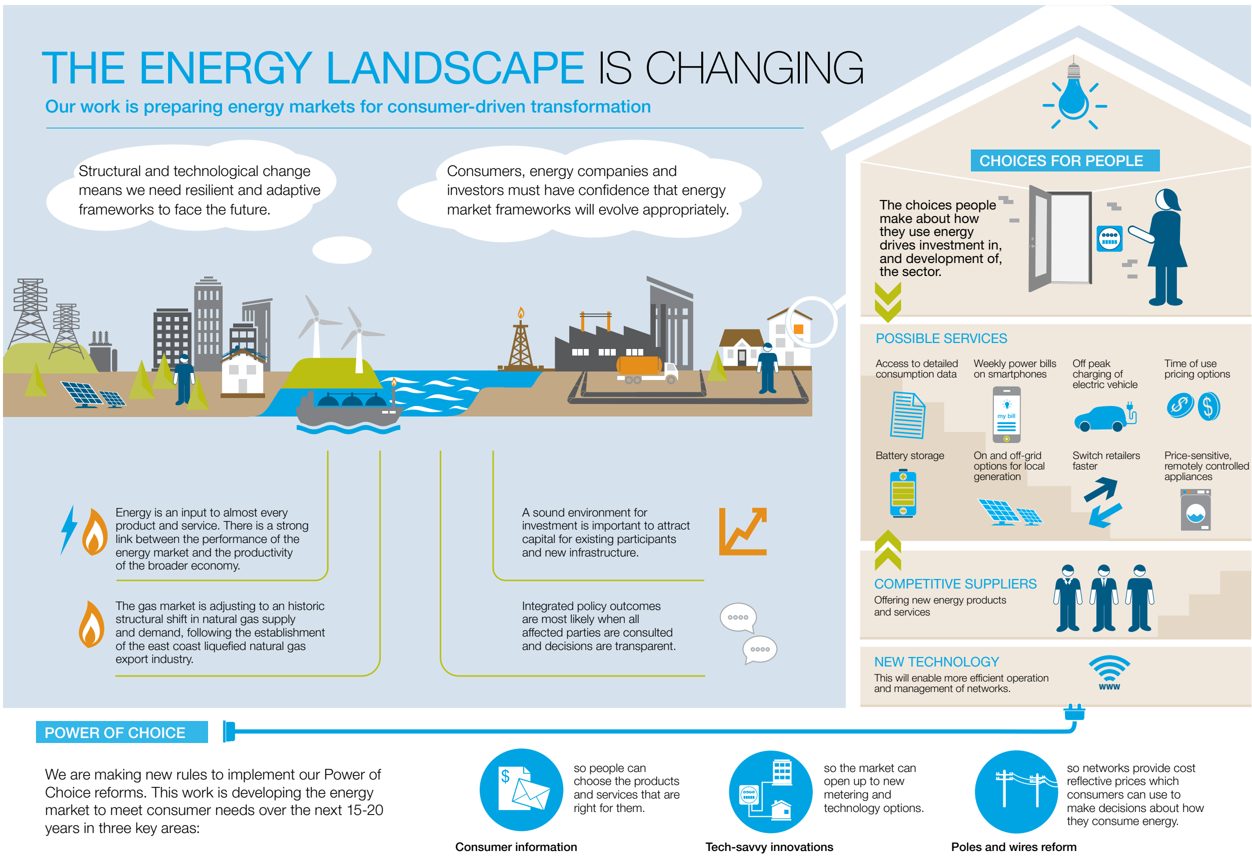
SA Power Networks has consistently been a leader with respect to identifying, understanding and planning for the transformational changes that are now underway in our sector. Acknowledging the potential scale and pace of these changes, we concluded in 2010 that helping to build a shared vision of the future energy and network needs, risks, opportunities and directions would be essential for our customers and for our business. In early 2011, we launched our Future Operating Model (**FOM**) initiative which outlines a vision of technological, customer and market change over a 15 year horizon, and illustrates the implications for our network business. We regularly review and update our FOM, and through it our vision of the long term future.

Energy usage patterns among our customers are changing radically. Since 2010 the rapid growth in penetration of solar photovoltaic (**PV**) generation has signalled the Distributed Energy Resource (**DER**) and 'two-way network' future before us. A quarter of South Australian households now have solar PV panels on their homes, illustrating the scale of change that just one key technology can trigger. Ahead, battery storage, electric vehicles, home energy management systems and mobile digital information and communication technologies will drive even more significant change. Taken together, the implications for SA Power Networks and our customers are profound.

Our latest FOM is consistent with the Australian Energy Market Commission's (**AEMC**) Power of Choice Review, released in late 2012. This review is now guiding a range of energy sector reform processes under the direction of the Council of Australian Governments Energy Council (**COAGEC**). A recent infographic released by the AEMC identifies many of the key changes underway in our industry (refer Figure 2.8).

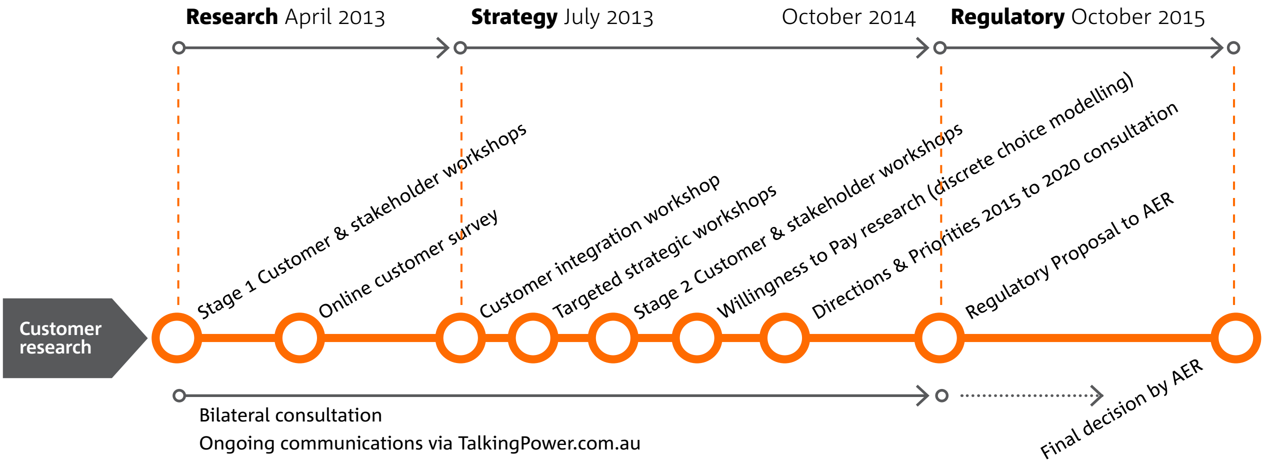
Tools like the FOM will help SA Power Networks make the most prudent and efficient investments on behalf of our customers, not just for the next five years, but for the next 15 and beyond. The most recent edition of the FOM can be found at **TalkingPower.com.au.**

Figure 2.8: AEMC infographic 2014 — The Energy Landscape is Changing



SOURCE: AEMC 2014

Figure 2.9: SA Power Networks' TalkingPower Customer Engagement Program



SOURCE: SA POWER NETWORKS 2014

2.3

Engaging with our customers for better outcomes — short and long term

All of our plans are developed within the clear context of delivering outcomes both in the short and long term interests of our customers. However, building a truly robust understanding of what those interests are is one of the great challenges for our industry and business.

SA Power Networks has a reputation for good communication and effective relationships with our customers, and we have a longstanding approach to tracking of customers' satisfaction over a range of our services to them. We also have a good record of successful stakeholder engagement in association with major projects and trials in local communities. We have had our own Customer Consultative Panel in place for more than 10 years.

This is a clear strategic direction for SA Power Networks, and the 'voice of our customers' increasingly influences our many activities, projects, processes and key performance indicators (**KPIs**).

The November 2012 National Electricity Rule (**NER**) changes that increased the focus on 'addressing the concerns of consumers identified through the course of consumer engagement' are consistent with our existing strategy. The design of our Customer Engagement Program was finalised in 2012, over 12 months before the AER's Consumer Engagement Guideline was released. We talked to our customers early enough to allow the time for both effective engagement as well as for timely consideration of customer feedback in order to factor it into our planning for the 2015–20 RCP.

Our comprehensive Customer Engagement Program, titled 'TalkingPower', aligns with the requirements of the AER's Consumer Engagement Guideline, the Stakeholder Engagement Standard (**AA1000SES**) and the International Association of Public Participation (**IAP2**) framework. The Customer Engagement Program is shown in Figure 2.9 in simplified form. It is discussed in Chapters 6 and 17 of this Proposal and further detail can be found in Attachment 16.6, and at **TalkingPower.com.au.**

TalkingPower has covered all key stakeholder groups and customer segments across South Australia, and opportunities to participate were widely promoted. Its scope has been comprehensive in terms of coverage of service areas and examination of short and long term issues. It has involved extensive qualitative and quantitative research, has benefitted from extensive involvement of senior management staff and has made use of independent experts and advanced techniques in a number of customer research and engagement fields.

All Customer Engagement Program stages adopted the explicit context of an indicative and easily understood distribution price path. Although minor variations on the pricing context were reflected at various stages of the program (taking account of the best information available at a given point in time), the general pricing context was that our aggregated services would be delivered with annual network price changes limited to no more than CPI. This was critical if customers were to be able to come to a personal judgement of value and balance with regard to mooted directions and priorities.

In turn, the program has provided us with a depth and breadth of information on customer concerns that has not previously existed, and has allowed us to address those concerns in our plans. Some of the high level insights that emerged from the Stage 1 qualitative and quantitative research initiatives are shown in Figure 2.10.

Figure 2.10: Customer Engagement Program Stage 1 key insights

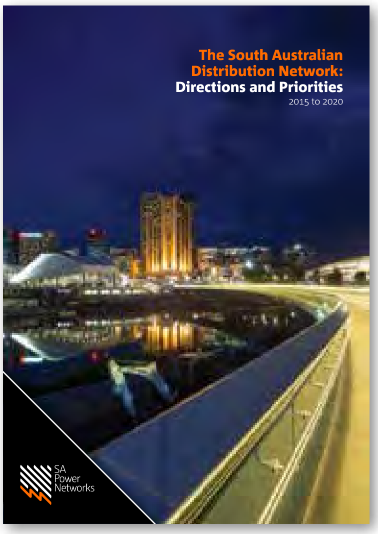
13 key 'insights' based on the views of South Australian electricity customers were drawn from the Research stage of the TalkingPower Customer Engagement Program. The program confirmed customers want us to:

1. Educate customers about the South Australian electricity industry and SA Power Networks' role.
2. Maximise opportunities to improve service experience.
3. Develop multi-channel communication strategies.
4. Continue managing assets and investment to drive reliability, manage risk and support economic growth.
5. Design vegetation management programs (tree pruning) to consider their visual impact.
6. Prioritise preventative maintenance to reduce risk.
7. Ensure Country Fire Service (**CFS**) Bushfire Safer Places have continuous power.
8. Maximise opportunities to improve the visual appearance of assets.
9. Consider improvements in public safety and reliability in asset planning.
10. Consider installing advanced meters.
11. Continue upgrades to support a two-way network.
12. Develop cost-reflective pricing tariffs.
13. Educate customers about new technology and industry change to help increase their satisfaction.

SOURCE: DELOITTE, STAGE 1 ONLINE CONSUMER SURVEY REPORT, JULY 2013.

The final stage of TalkingPower, in May-June 2014, involved consultation on our 'Directions and Priorities 2015 to 2020' consultation document (refer Figure 2.11). This document outlined our preliminary plans and proposals for the 2015–20 RCP, and represented a new benchmark in our sector with regard to clarity and transparency on our proposals of services for the future, and importantly regarding the prices customers can expect to pay for them. This document can be accessed at **TalkingPower.com.au.**

Figure 2.11: 'Directions and Priorities 2015 to 2020' consultation document



2.4

Services to our customers drive our Regulatory Proposal

SA Power Networks is well underway in an ongoing long term effort to become a more customer-focussed DNSP, built upon a foundation of systematic and effective engagement practices developed over many years.

Accordingly, this Proposal, like our 'Directions and Priorities 2015 to 2020' consultation document, is largely structured around the services we provide to customers. This approach reflects the central role of the voice of the customer in our initiatives for the next RCP.

The high level services we provide to our customers are:

- **Keeping the power on for South Australians** *(refer Chapter 9)*
- **Responding to severe weather events** *(refer Chapter 10)*
- **Safety for the community** *(refer Chapter 11)*
- **Growing the network in line with South Australia's needs** *(refer Chapter 12)*
- **Ensuring power supply meets voltage and quality standards** *(refer Chapter 13)*
- **Serving customers now and in the future** *(refer Chapter 14)*
- **Fitting in with our streets and communities** *(refer Chapter 15)*
- **Capabilities to meet our challenges** *(refer Chapter 16)*

In Chapters 9 through to 16 we have outlined, by reference to these key 'service areas', a range of regulatory obligations that we must comply with and how we propose to do that whilst, at the same time, achieving the directions and priorities that customers want us to take and address, for the short and long term.

These chapters identify changes from programs presented in our 'Directions and Priorities 2015 to 2020' consultation document based on customer feedback. Other changes have also occurred as we finalised our Proposal.

Overall, our Regulatory Proposal is highly reflective of our consultation document, but we note the following changes being made between the consultation document and the Proposal:

- Total capital expenditure has reduced, in part due to feedback from stakeholders who encouraged a review of less-critical projects in the interests of balancing price concerns of customers, and more significantly due to refinement of some complex expenditure proposals.
- Total operating expenditure has increased, due to refinement of a number of expenditure proposals.
- Rate of Return has decreased, reflective of changes in market risk free interest rates and corporate bond rates.
- Growth in forecast energy consumption has been revised downwards, based on the latest forecasts from the Australian Energy Market Operator (**AEMO**). This growth path affects average price forecast outcomes only.

2.5

The key areas of focus in this Proposal

The key programs of work encompassed by this Proposal which have been identified through our Customer Engagement Program, and the service areas that they relate to, are:

- network augmentation and security (Growing the network in line with South Australia's needs);
- network asset replacement (Keeping the power on for South Australians);
- hardening the network (Responding to severe weather events);
- vegetation management (Fitting in with our streets and communities);
- bushfire risk mitigation and road safety (Safety for the community);
- customer service strategy (Serving customers now and in the future); and
- cost-reflective tariffs and demand side participation (Serving customers now and in the future).

These are briefly discussed in turn, followed by an explanation of more detailed work program items, their total costs, and the benefits and outcomes accruing from them.

Network augmentation and security
SA Power Networks invests in the distribution network to ensure adequate capacity is available to meet peak demand requirements from customers. South Australia is widely recognised as having one of the 'peakiest' customer load profiles in the world, largely driven by air conditioning loads in summer. SA Power Networks is required to build infrastructure to meet the peak demand that occurs for less than 2% of the year.

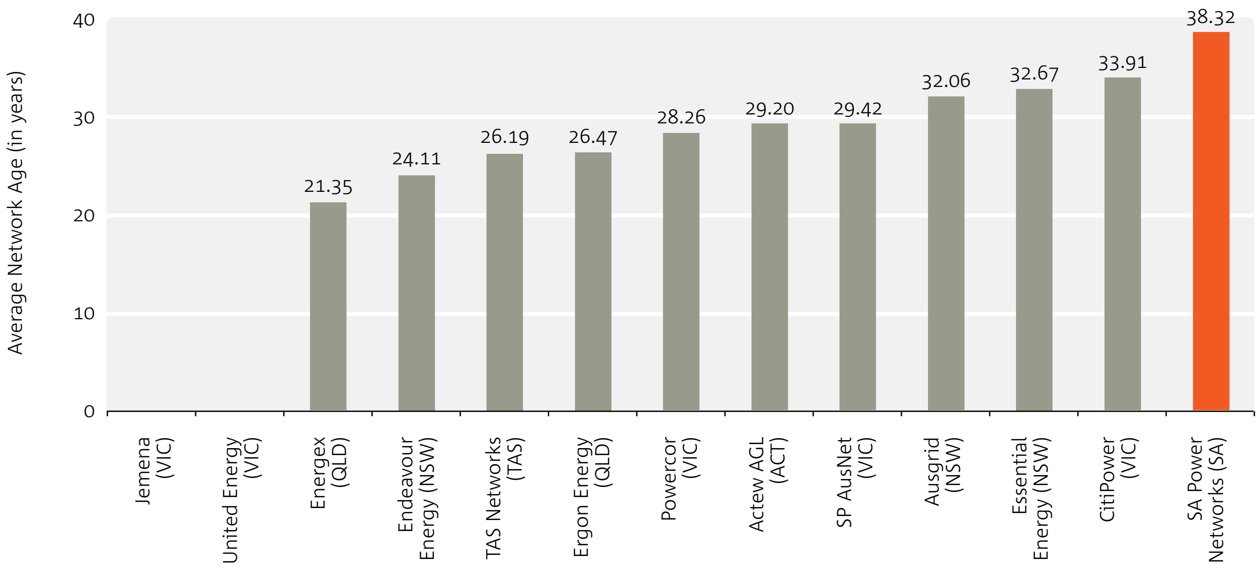
Since 2010, global demand (ie at the aggregated distribution system level) has moderated, and is currently forecast to be flat over the 2015–20 RCP. However, distribution network growth occurs at the local level, and we must build the network to meet local area demands which are impacted by a complex range of factors including pockets of regional growth, urban infill developments, more single person households as the population ages, installation of solar panels and customers' response to energy efficiency. Although the number of local areas with short term augmentation needs has softened in line with global demand trends, there still remains a material number of local augmentation projects for the 2015–20 RCP.

Specific regions of South Australia also have unique circumstances that drive security investments. Kangaroo Island is an iconic tourism destination off the coast of the Fleurieu Peninsula. The island is supplied by an undersea cable that was installed in 1993. The cable is close to the end of its predicted 30 year life, and economic analysis indicates that installation of a new cable in the 2015–20 RCP is the most prudent and efficient approach.

In the 2015–20 RCP, it remains important that our investments in network capacity meet customer needs at the right time and the right place, and that we continue to connect customers efficiently and promptly.

Network asset replacement
The South Australian distribution network covers a vast territory. Most of the network is above ground with 70% of the network assets serving the 30% of customers outside of metropolitan Adelaide. Much of our existing network assets were built in the 1950s, 1960s and early 1970s. SA Power Networks now operates one of the oldest asset fleets in Australia (refer Figure 2.12).

Figure 2.12: Average Australian distribution network ages



Notes
– Data is sourced from AER Category Analysis Regulatory Information Notices (**RIN**) data, published 25 June 2014.
– Category Analysis data supplied to the AER by Jemena was in the incorrect format and has therefore been excluded from this analysis.
– Category Analysis data supplied to the AER by United Energy was inclusive of disposed assets and has therefore been excluded from this analysis.

SOURCE: SA POWER NETWORKS ANALYSIS 2014

SA Power Networks is obligated under the *Electricity Act 1996* and its Distribution Licence to prepare and comply with a Safety, Reliability, Maintenance and Technical Management Plan (**SRMTMP**). This plan lays out the safety and technical compliance management framework agreed between the South Australian Office of the Technical Regulator (**OTR**) and SA Power Networks, and is approved annually by the Essential Services Commission of South Australia (**ESCoSA**).

As approved by the AER, SA Power Networks has significantly increased asset inspection activities during the current RCP. These inspections have confirmed that a substantial increase in asset replacement works must be undertaken over the next 5–15 years if we are to appropriately manage the increasing level of network risk. To quantify the asset replacement work for the next RCP, we have used a range of methods including condition based risk management (**CBRM**) modelling.

SA Power Networks has spent 60% more than the AER approved allowance on asset replacement in the 2010–15 RCP. This work has focussed on asset replacement and refurbishment in the highest priority areas, and in the case of poles, where possible we have utilised much cheaper pole plating (as opposed to pole replacement) to minimise the cost. Notwithstanding this investment, the deteriorating condition of our assets has seen our network risk increase significantly.

It is now essential that we increase the level of asset replacement works over the 2015–20 RCP, rectifying asset defects in a systematic, prudent, timely and efficient manner. In doing so, over the next 10 years SA Power Networks will return the asset portfolio to risk levels consistent with the SRMTMP, maintain safety and reliability of the network and enable compliance with our obligations.

Hardening the network

Although underlying levels of reliability for the distribution network are stable, the overall level of reliability, which includes the impacts of Major Event Days (**MEDs**), is deteriorating. MEDs are strongly correlated with severe weather events. The number and severity of severe weather events that cause significant damage to our above ground network has significantly increased in recent years. CSIRO and Bureau of Meteorology reports indicate a likely continuation in the trend of severe weather events. The South Australian distribution network has entered a period in which the challenge to maintain overall reliability outcomes for customers will remain high.

Lightning and high winds are the most damaging. Lightning strikes directly damage network equipment, while high winds can blow limbs or whole trees onto power lines. As a result power interruptions can be of long duration in such circumstances, especially for customers in more remote areas where the network is more sparse, and radial lines are longer.

Notwithstanding that a regulated Guaranteed Service Level (**GSL**) regime applies in our State, including for MEDs, customers have told us that we should improve the resilience of the existing above ground network through cost-effective enhancements, and better monitoring, control and automation equipment. In our Customer Engagement Program, 88% of customers supported further protecting the network to harden against lightning and storms.

During the 2010–15 RCP SA Power Networks commenced work on identifying and hardening parts of the network likely to be affected or which have historically been impacted by severe weather events.

In the 2015–20 RCP we propose to continue cost effective hardening of specific areas of the network, and to continue to explore opportunities to deploy new technologies and approaches that can improve the reliability and service experience of our customers during severe weather events.

Vegetation management

South Australian legislative requirements in regard to maintaining clearances between power lines and vegetation are highly prescriptive. SA Power Networks is required to inspect and clear vegetation from around overhead power lines so that prior to the next scheduled inspection and clearance (at a maximum of three yearly cycles) the vegetation does not grow, regrow or bend into the ‘clearance zone’ around the power line, in winds that might reasonably be expected in the area.

SA Power Networks is not permitted to clear vegetation beyond the applicable ‘buffer zone’ surrounding the power line for the purposes of enhancing the appearance, stability or health of remaining vegetation. The combined consequence of these requirements is that sub-optimal tree and streetscape outcomes frequently occur in South Australia.

Significant and persistent community concern over the aesthetics of current vegetation management practices and outcomes has been clearly reflected in our TalkingPower Customer Engagement Program.

As a result of the strength of this concern, SA Power Networks conducted extensive stakeholder engagement and research to explore options for improved outcomes that the community would value, relative to the current situation. This work has shown there is a Willingness to Pay for enhanced vegetation management approaches across South Australia. This would entail moving away from a one-size-fits-all approach and working towards a more sustainable and long-term approach that includes improved trimming practices. In the 2015–20 RCP, we propose to enhance our vegetation management systems and practices to improve vegetation management outcomes in the long term (in line with community preferences, but within legislated requirements). Initial experience during 2014/15 in a number of metropolitan and regional areas indicates that this approach will lead to far greater levels of satisfaction in the community.

Bushfire risk mitigation and road safety
Safety for the community and our employees is our highest priority. Unfortunately, recent interstate bushfire disasters and weather trends indicate that bushfire risks are increasing in Australia, and more particularly for South Australia.

Recent modelling estimates the maximum probable loss associated with a single fire as a result of ignition within SA Power Networks' electricity distribution network to be $500m, for a single major fire within the Adelaide Hills. If multiple fires occurred on the same day, the maximum probable loss within the SA Power Networks service area could be up to $1 billion.

SA Power Networks has stringent bushfire risk management systems, but these must continue to be improved to match good electricity industry practice. Detailed analysis of the Victorian Power Line Bushfire Safety Taskforce (**PBST**) findings shows that important improvements can be made in this regard. These include inspection regimes, design and construction standards, and tree trimming/vegetation clearance practices. It is also important that SA Power Networks supports South Australian Government and community bushfire safety strategies. Accordingly in the 2015–20 RCP we propose to enhance our bushfire risk mitigation program in a number of key areas. Consistent with community expectations, we will also work towards 'CFS Bushfire Safer Places' having reliable power supplies.

Our Customer Engagement Program has also revealed strong community concern about road safety risks which arise when power poles are in close proximity to road users. Customer Willingness to Pay research has shown there is support for targeted undergrounding or relocation of poles to reduce these risks, and in the 2015–20 RCP we propose to implement a targeted program of undergrounding to reduce the potential for vehicle collisions with stobie poles, in close consultation with Government stakeholders.

Customer service strategy
Customers are experiencing a level of connectivity and information access across a range of industries that is transforming their expectations of SA Power Networks. Our Customer Engagement Program shows that customers expect greater choice and control over all of their services. They expect to be able to install new technologies such as solar PV and electric vehicles with a minimum of fuss, and they expect service providers like us to support their preferences. Customer service offerings that have been suitable in the past may not be fit for the future.

SA Power Networks is committed to a service model that keeps the voice of the customer, and delivery on their needs, at the centre of our business. Our Customer Service Strategy, built on extensive research and customer engagement, represents a transformational approach to customer service in our industry, and has been key to our planning for the next five years.

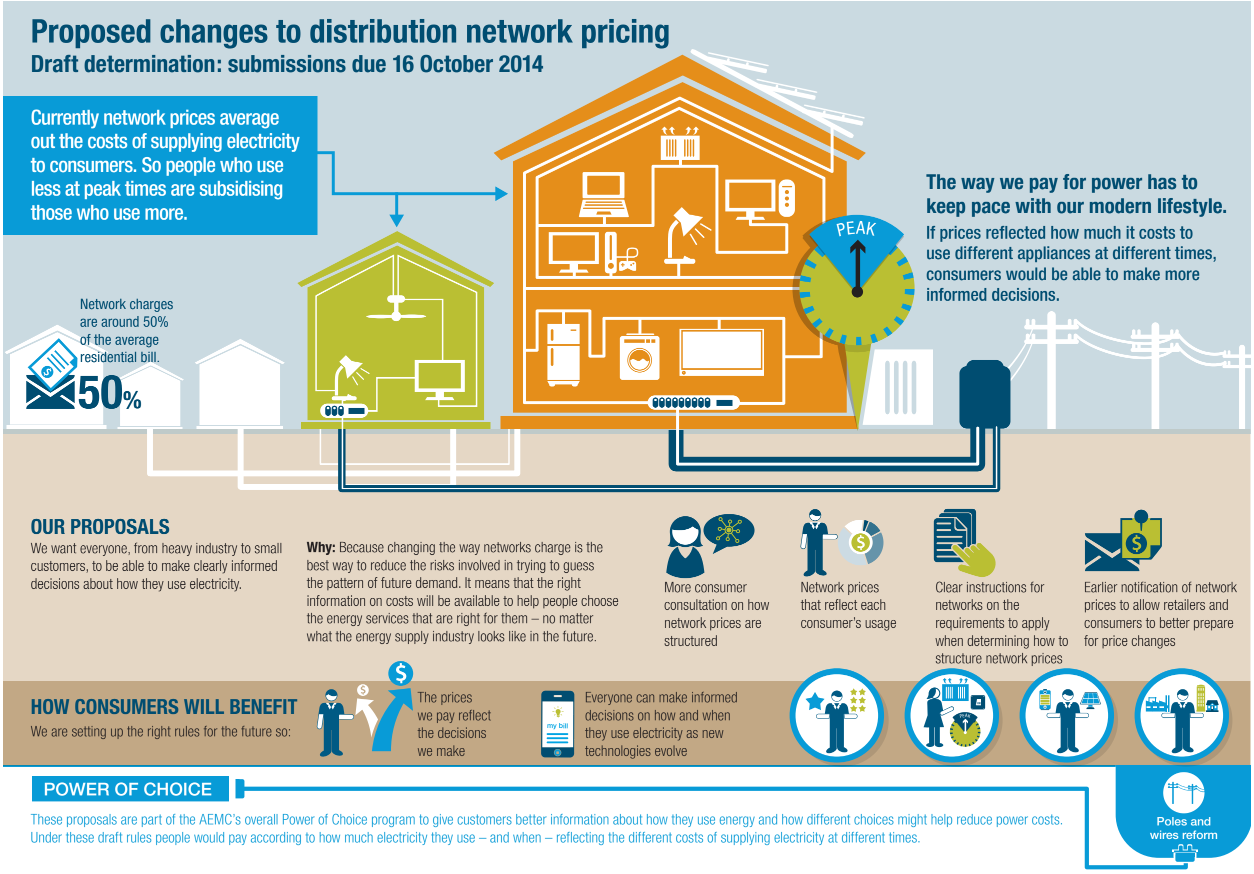
Important customer service system investments are required in the coming years. The most significant is the need to replace our legacy billing system, and the need to upgrade our market-facing systems for business to business transactions with retailers and AEMO in order to maintain a reliable, secure service and support the AEMC's regulatory reforms arising from the Power of Choice review.

In the 2015–20 RCP, we propose to deliver information, service, communications and self-service options that our customers value, provide accurate and timely information on service status and power restoration activities, and provide increasing levels of advisory information in line with customers' current and future electricity needs.

Cost-reflective tariffs and demand side participation
We have already discussed the scale of transformative change that is underway in our industry, in terms of technology, customer expectations, network usage, and competition. SA Power Networks believes that important steps are required now to enable a timely and smooth transition to a much more complex future. This future will involve new ways of pricing for network services that promise to have wide-ranging benefits for customers in the longer term.

An AEMC infographic identifies many of the factors driving the distribution network pricing NER Rule change process that is currently nearing completion (refer Figure 2.13).

Figure 2.13: AEMC infographic 2014 — Distribution pricing draft determination



SOURCE: AEMC 2014

In the 2015–20 RCP, we propose to continue to facilitate the efficient connection of new technologies as we move toward the two-way network of the future. In line with AEMC directions, we will introduce cost-reflective tariffs for small customers which will promote efficient investment in Distributed Energy Resources (**DER**). These new tariffs will require more advanced metering, and on this basis, SA Power Networks proposes to install 'smart-ready' meters from the beginning of the 2015–20 RCP as our standard meter in new and replacement situations to support the new tariffs as well as avoiding continued investment in 'dumb' meters that are likely to be redundant over a very short timeframe. Over the period, we also propose to transition customers to monthly meter reading, providing customers with more timely, detailed data with which to manage their energy use and peak demand. We will also invest in systems to manage the increased volumes of metering and network data likely to be driven by the introduction of contestable metering.

Summary of our 2015–20 RCP work programs

Table 2.1 summarises our proposed work programs for the 2015–20 RCP, grouped according to the high level service areas identified earlier. The table indicates the key work program items, the total capital expenditure associated with the work programs plus any associated step change operating expenditure costs (per annum). Key benefits and outcomes from each program of work are also indicated.

The proposed capital expenditure program for the 2015–20 RCP is $2,485.5m for Standard Control Services (**SCS**). Full details of the capital expenditure program can be found in Chapter 20.

Combining the 2013/14 base year operating expenditures (including adjustments to the base year) of $240.44m per annum with the total step changes for the five year period of $216.8m, applying the 'trend' (otherwise known as 'rate of change') parameters of $108.1m, and adding debt raising costs for the five year period of $27.0m, we arrive at SA Power Networks' total forecast operating expenditures for the 2015–20 RCP of $1,554.1m (**SCS**) as shown in Table 2.2. Full details of the base year, adjustments, rate of change parameters, and financing related costs can be found in Chapter 21.

Note that operating expenditure 'step changes' stem from the AER's 'base-step-trend' approach to forecasting operating expenditures and represent increases above our expenditures in 2013/14. This process is detailed in Section 21.4 and Attachment 7.5, SA Power Networks' Expenditure Forecasting Methodology.

Table 2.1: Summary of proposed program of work for the 2015–20 RCP*

Keeping the power on for South Australians — Refer Chapter 9	
Capital expenditure (June 2015 $ M)	802.8
Step change operating expenditure pa (June 2015 $ M)	6.9
Programs of work	**Benefits and outcomes**
• invest in optimal replacement and/or refurbishment of ageing assets based on condition • continue our Condition Based Risk Management (**CBRM**) asset inspection and data collection program • invest in integrated IT and communications systems that support the application of modern CBRM approaches and operational management of the network (incl. SCADA) • continue investing in our oil filled asset risk management program • install a new Kangaroo Island submarine cable to secure supply to the island	• compliance with regulated obligations • prudent and efficient maintenance of the safety of the network • prudent and efficient maintenance of the current underlying network reliability performance • prudent and efficient management of environmental impacts of oil-filled assets • return of the asset portfolio to acceptable risk levels in the longer term • sustainable asset inspection regime that enables more accurate risk assessments • more effective condition and risk management approaches • prudent and efficient supply arrangements for Kangaroo Island • alignment with customer expectations as revealed in our Customer Engagement Program

Responding to severe weather events — Refer Chapter 10	
Capital expenditure (June 2015 $ M)	58.8
Step change operating expenditure pa (June 2015 $ M)	1.9
Programs of work	**Benefits and outcomes**
• continue investment in hardening sections of the network most vulnerable to lightning and storms during Major Event Days (**MEDs**) • continue long term program to manage degradation of ageing assets which impact underlying reliability performance (ie for new and existing assets not included in asset replacement works) • address MED resilience for specific remote communities (Elliston and Hawker) • address MED resilience for outlier worst performing feeders • trial micro-grid technologies as a means of addressing MED resilience for a community supplied by a poorly performing radial line • transfer emergency radio communications for our field crews from proprietary system to the South Australian Government Radio Network • enhance customer communications during major service events	• compliance with regulated obligations • prudent and efficient management of the current underlying network reliability performance • reduction in number and duration of supply interruptions experienced by customers due to (increasing) MEDs • increased capability to deploy innovative technologies to address MED resilience • more secure, effective and efficient operational communications for major service events • more effective and timely customer communications before and during major service events • alignment with customer expectations as revealed in our Customer Engagement Program

*Note that figures exclude superannuation and equity raising costs, which reduces cost by $43.4m

Safety for the community — Refer Chapter 11	
Capital expenditure (June 2015 $ M)	406.6
Step change operating expenditure pa (June 2015 $ M)	6.2
Programs of work	**Benefits and outcomes**
• progressively reinforce power supply to Country Fire Service (**CFS**) Bushfire Safer Places, including targeted undergrounding where appropriate • implement findings from the Victorian Power Line Bushfire Safety Taskforce (**PBST**) where they are appropriate for South Australian conditions to align with good electricity industry practice • invest in a tree removal and replacement program in Bushfire Risk Areas, in close consultation with local stakeholders (net of vegetation management cost offsets) • in existing high risk network locations (eg known areas of repeated vegetation incursion into power line clearance zones) utilise targeted undergrounding where most appropriate • increase the frequency, safety and efficacy of inspections in Bushfire Risk Areas to align with good electricity industry practice • continue managing vegetation clearance to ensure compliance in Bushfire Risk Areas • continued investment in prioritised strategies to address the community and workforce safety risks posed by a range of older assets • implement a targeted program of undergrounding to reduce the potential for vehicle collisions with stobie poles, in close consultation with Government stakeholders • invest in community education to improve safety awareness around power lines	• compliance with regulated obligations • integrated support for South Australian Government and community bushfire safety strategies (ie CFS Bushfire Safer Places) • alignment with recent changes to Australian good electricity industry practice (following interstate bushfire disasters) • prudent and efficient management of overall safety risk levels • treatment of specific safety risks to the community and workforce • more effective and timely corporate communications on community safety around power lines (eg 'Look Up and Live') • alignment with specific customer preferences as revealed in Willingness to Pay discrete choice modelling • alignment with customer expectations as revealed in our Customer Engagement Program

Growing the network in line with South Australia's needs — Refer Chapter 12	
Capital expenditure (June 2015 $ M)	439.2
Step change operating expenditure pa (June 2015 $ M)	0.3
Programs of work	**Benefits and outcomes**

• invest efficiently by aligning our plans with changing industry, customer and demographic needs — including through advanced demand trend monitoring and analysis
• continue to maintain close connections with stakeholders to ensure that the implications for planned infrastructure developments are understood and planned for
• reinforce our network through augmentation and capacity projects to meet the demand for Standard Control Services (**SCS**), driven by:
  • compliance with the Electricity Transmission Code (**ETC**)
  • locational demand changes within the distribution network
• accommodate non-network solutions to network constraints in line with the AER's Regulated Investment Test-Distribution (**RIT-D**) processes
• connect customers efficiently in line with our regulatory obligations
	• compliance with regulated obligations
	• timely provision of network capacity in line with customers' needs
	• timely new, upgraded or altered connections for customers
	• a more adaptable network that can accommodate customers' changing preferences for non-network solutions and distributed energy resources (**DER**)
	• alignment with customer expectations as revealed in our Customer Engagement Program

Ensuring power supply meets voltage and quality standards — Refer Chapter 13	
Capital expenditure (June 2015 $ M)	111.7
Step change operating expenditure pa (June 2015 $ M)	0.2
Programs of work	**Benefits and outcomes**
• proactively and selectively monitor the low voltage (**LV**) network to more accurately plan LV capacity upgrades in a rapidly evolving DER and technology environment • improve our knowledge of and support for customer take-up of DER (incl. micro-generation, energy storage and electric vehicles) • address quality of supply issues in the worst performing areas of the network	• compliance with regulated obligations • maintenance of customer quality of supply • improved timeliness and optimisation of future network upgrades • enhanced customer service capability with regard to enquiries on quality of supply • helping to enable a more adaptable network that can accommodate customers' changing preferences for DER • enhanced capability to understand and deal with DER issues as we move towards a two-way network with increased Demand Side Participation (**DSP**) • alignment with customer expectations as revealed in our Customer Engagement Program

Serving customers now and in the future — Refer Chapter 14		
Capital expenditure (June 2015 $ M)	104.8 (SCS)	49.0 (ACS)
Step change operating expenditure pa (June 2015 $ M)	8.4 (SCS)	17.4 (ACS)*
Programs of work	**Benefits and outcomes**	
Adapting to changing customer expectations: • further develop self-service options that our customers value • develop multi-channel communication tools to interact with our customers • strengthen data collection and information flows from our field personnel to customers to provide accurate and timely information on service and restoration activities • implement systems to allow a single view of the customer and enable customer service to be tailored and to be responsive to their needs • replace our end-of-life billing system • upgrade our market-facing systems to support AEMC reforms • provide information and advice for customers' current and future electricity needs Promoting Demand Side Participation (**DSP**): • introduce cost-reflective tariffs for small customers to promote efficient investment in DER — for new and replacement meter installations (and opt-in customers) • introduce 'smart ready' meters as our standard meter for small customers to support cost-reflective tariffs and avoid continued investment in obsolete metering equipment	• compliance with regulated obligations • enhanced self-service customer service options • more accurate and timely restoration service information for customers • accurate and timely information for customers so they can understand and manage their electricity costs • more cost-reflective signalling of network costs for small customers • reduced cross-subsidisation between customers with or without large air-conditioning systems and DER such as solar photovoltaic (**PV**) panels • alignment with South Australian Government policy directions on metering and tariffs • alignment with AEMC draft determination on distribution pricing NER change • be a trusted source of information and advice for customers' current and future electricity needs • alignment with customer expectations as revealed in our Customer Engagement Program	

*Note: Alternative Control Services (**ACS**) operating expenditures, which relate to provision of meters and meter data services, are not built up through the base-step-trend method, but are shown here for convenience. The amount shown for ACS reflects total operating expenditure.

Fitting in with our streets and communities — Refer Chapter 15	
Capital expenditure (June 2015 $ M)	46.3
Step change operating expenditure pa — (June 2015 $ M)	4.5
Programs of work	**Benefits and outcomes**
• continue undergrounding of existing power lines in specific areas under the State Government's Power Line Environment Committee (**PLEC**) scheme • implement an enhanced program of vegetation management to improve tree-trimming outcomes: – two year trimming cycle and tree removal and replacement program in non-bushfire risk areas – advanced tree trimming practices – improved community communications – detailed vegetation data management • build fit-for-setting substation facades where appropriate	• compliance with regulated obligations • improved community aesthetics and amenity • reduced vegetation management costs in the long term • alignment with specific customer preferences as revealed in Willingness to Pay discrete choice modelling • alignment with customer expectations as revealed in our Customer Engagement Program

Capabilities to meet our challenges — Refer Chapter 16	
Capital expenditure (June 2015 $ M)	558.7
Step change operating expenditure pa (June 2015 $ M)	15.3
Programs of work	**Benefits and outcomes**
• continue to continuously improve our industry-leading strategy and governance capabilities, including through comprehensive stakeholder engagement • continue to drive our systems and culture to support customer service and associated outcomes • address customer preferences for enhanced provision of industry, corporate and advisory information • improve integration of technologies and systems to support delivery of services to required standards • execute our workforce strategy to enable safe and efficient delivery of our programs of work • continue investing in modern and safe standards of property, equipment and vehicles to deliver our programs of work	• compliance with regulated obligations • alignment with regulatory directions, and customer and community concerns — provision of the right services at the right time, efficiently • strong customer and stakeholder relationships • improved customer service outcomes • better information for customers • accurate information for AER benchmarking and oversight • improved asset, process, project and program management • deliverable, efficient and safe work programs • improved knowledge capture and use for the future • alignment with customer expectations as revealed in our Customer Engagement Program

2.6

Other factors contributing to calculation of revenue requirements and price outcomes

The capital and operating expenditures summarised in Table 2.1 are key components of the building block revenue requirement calculation from which an average price outcome for the next RCP can be forecast. The other key factors that contribute to the price outcome forecast are:

- the Regulated Asset Base (**RAB**) as detailed in Chapter 25;
- the Rate of Return as detailed in Chapter 26 (applied to the RAB to derive Return on Capital);
- regulatory depreciation of assets as detailed in Chapter 27;
- the incentive scheme carryover amounts as detailed in Chapters 23 and 24;
- the allowance for the cost of corporate income tax as detailed in Chapter 28; and
- the South Australian energy sales growth forecast as detailed in Chapter 12.

We have used a Rate of Return (nominal vanilla Weighted Average Cost of Capital) of 7.62%, based on a Return on Equity of 10.45% and a Cost of Debt of 5.74%.

The averaging period for the market interest rates used to calculate the above Cost of Debt for the Proposal was the 20 business day period ending on 31 August 2014. We will seek agreement with the AER for the averaging periods to be applied during 2015–20.

We have calculated our tax allowance based on a value of imputation credits of 0.25, consistent with the 2011 Australian Competition Tribunal decision and supporting market data.

The key factors are summarised in Table 2.2.

Table 2.2: SCS and ACS building block revenue requirement factors for the 2015–20 RCP (June 2015 $)

Building block factor	SCS	ACS
Operating expenditure	$1,554.1m	$86.2m
Regulated Asset Base (at 2020)	$4,957.9m	$86.8m
Rate of Return	7.62%	7.62%
Depreciation	$862.2m	$37.8m
Incentive scheme carryover amount	$13.9m	n/a
Net shared assets cost reduction	($2.3m)	n/a
Tax allowance	$384.9m	$22.6m
Energy sales growth forecast (average over 5 years)	0.0%pa	

2.7

Price impacts of this Proposal

The tables below detail the annual revenue requirement and average price outcomes (as appropriate) for:

- Standard Control Services, Table 2.3; and
- Alternative Control Services, Table 2.4.

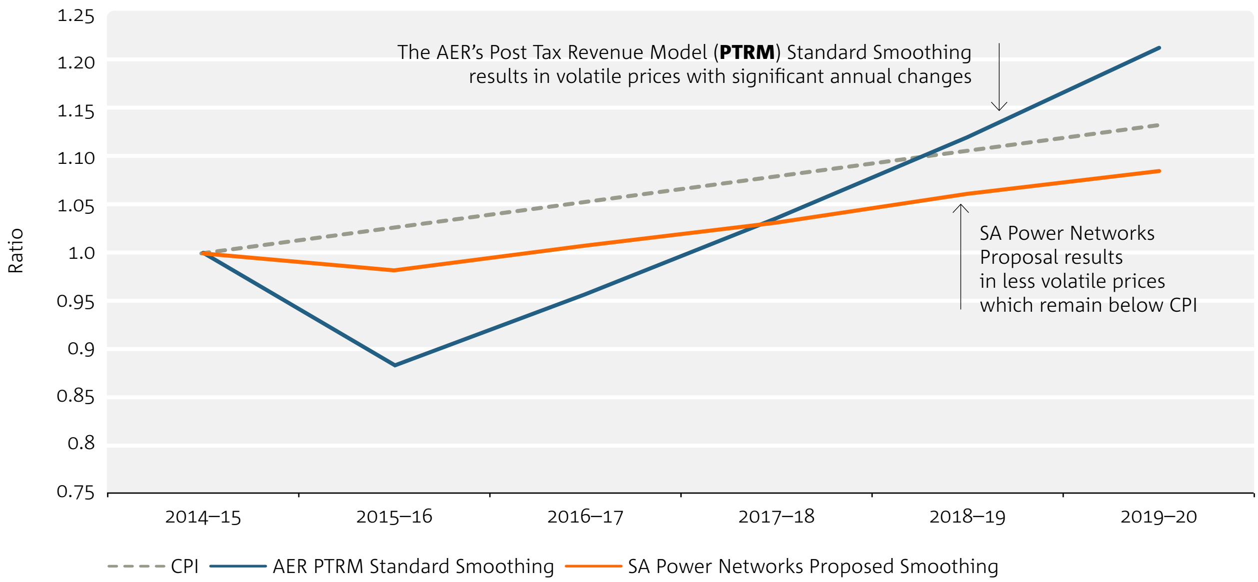
Standard Control Services

The P_0 reduction of 4.3% and zero X-factors shown in Table 2.3 reflect SA Power Networks' preferred revenue requirement smoothing approach which reduces price volatility, in line with AEMC pricing policy objectives. The AER's standard smoothing approach would see more volatile prices with a P_0 reduction of 13.4% and subsequent annual real price increases of 5.2% (refer Figure 2.14).

Table 2.3: Revenue requirement and price path outcomes — SCS (June 2015, $ million)

Component	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Return on capital		284.7	302.9	322.5	340.1	356.4
Regulatory depreciation		129.0	153.4	174.9	194.9	210.1
Operating expenditure		285.7	298.9	315.9	324.5	329.1
Carry-over amount		10.1	16.3	0.1	(12.6)	-
Net shared assets cost reduction		(0.8)	(0.8)	(0.8)	-	-
Tax allowance		74.4	74.9	76.3	78.8	80.5
Unsmoothed revenue requirement		783.0	845.6	888.9	925.8	976.2
Smoothed revenue requirement	918.7	879.4	879.4	879.4	879.4	879.4
Revenue and price P_0 and X-factors		4.3%	0.0%	0.0%	0.0%	0.0%

Figure 2.14: Comparison of SCS price smoothing outcomes (% change year on year)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Alternative Control Services
Alternative Control Services (**ACS**) are customer-specific or customer-requested services. Costs for ACS are paid by the customers using the service. The provision of meters and meter data services have been classified by the AER as ACS since these services are expected to become fully contestable during the 2015–20 RCP.

Refer to Table 2.4 for our proposed revenue path for ACS.

2.8

Outcomes and benefits for South Australians

SA Power Networks is a high-performing DNSP, with strong outcomes over many years in areas including reliability, customer service, and safety. We are also a highly efficient DNSP, and have a long track record of prudent and measured investment in distribution network infrastructure for South Australians.

Over recent years it has become clear that very significant changes are underway in many areas of our operating environment, including in terms of customers' expectations, new energy and network technologies, and regulation. We have been proactive and thorough in terms of considering and evaluating these changes and we have also had the opportunity to consider customer perspectives on many of them throughout the course of our Customer Engagement Program.

SA Power Networks believes that our proposals for 2015–20 strike the right balance of investments to support optimal service provision for South Australians in both the short term and long term, and pricing outcomes for customers.

At all stages of the Customer Engagement Program, our customers have consistently recognised the need to invest for the short term and the longer term. They have also recognised that our less direct services, such as 'safety for the community', are just as relevant to them and their broader community as, say, 'keeping the power on'. The substantial changes underway in the industry and associated markets have also been noticed by our customers, and the value of 'cost-reflective pricing', and what that means for them and the community, is also recognised.

Table 2.4: Revenue path requirement outcomes — ACS (June 2015, $ million)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
SA Power Networks revenue path requirement	28.0	30.0	32.6	35.8	38.5	41.6
Revenue P_0 and X-factors	-	7.1%	8.6%	9.8%	7.7%	8.0%

This all confirms that this Regulatory Proposal is like none that have preceded it. The 2015–20 RCP requires SA Power Networks to look well beyond this five year period, and to propose a transition path through uncertain times to a very different future. This does not mean that the distribution network will disappear any time soon. The distribution network of today will change, and become a more valuable asset to South Australians, as it supports new opportunities that will accompany the two-way network and the associated Demand Side Participation.

To fulfill the role we believe customers and stakeholders want us to undertake, we need to build on our existing skills and capabilities, and develop new ones. In this next phase, it is important that we:

- continue to drive efficiencies in all that we do;
- consolidate our customer focussed philosophy that aims to grow value for our customers;
- become more expert at communicating and engaging with stakeholders and customers;
- improve our systematic asset management capabilities;
- increase our ability to innovate and to deliver valuable new approaches and services;
- operate integrated systems and technologies that provide the information to support efficiency and service development; and
- develop our organisation to sustain these new and improved capabilities.

As always, price is a key concern for our customers. From the start of our planning and engagement for the next RCP, we have consistently acknowledged the need to balance investment needs with the pricing preferences of our customers. We are pleased that our Proposal will deliver the investments that support optimal service provision for South Australians in both the short term and long term, while containing network prices to an average price path of less than CPI.

Specifically, by 2020 SA Power Networks will have delivered:

1. Continued underlying network reliability performance at current levels;
2. Improved MED reliability performance for worst-served customers in targeted areas of the network;
3. Innovative technologies to improve MED resilience in the future;
4. Secure supply arrangements for Kangaroo Island that are prudent and efficient;
5. Management of the condition and safety of network assets;
6. Progressive return of the asset portfolio to acceptable risk levels in the longer term;
7. Continued management of environmental risks from network assets;
8. Timely network capacity and connections in line with customers' needs;
9. A more adaptable network that meets supply quality standards and can accommodate distributed energy resources (**DER**);
10. Management of overall bushfire safety risk levels;
11. Rectification of specific safety risks to the community and our workforce;
12. Secure power supply for prioritised Country Fire Service Bushfire Safer Places;
13. More accurate, timely and secure operational communications for service events;
14. More valuable and timely informative/educational communications on a range of service, safety and industry topics;
15. Expanded and improved self-service options for customers;
16. New cost-reflective tariffs that improve signalling of network costs to residential and small business customers;
17. Reduced cross-subsidies between customers with or without DER (such as solar PV panels);
18. Enhanced vegetation management approaches that improve visual amenity and have potential for reduced costs in the longer term;
19. Better alignment of SA Power Networks' directions with stakeholder needs, providing the right services at the right time, efficiently; and
20. More accurate information for AER benchmarking and oversight.

Conclusion

SA Power Networks' Regulatory Proposal for the 2015–20 RCP represents a comprehensive account of a great many issues, changes, directions, strategies and outcomes with respect to electricity distribution network services for South Australians.

The AER must now consider our proposals, and make a determination on the extent to which SA Power Networks' directions are an appropriate response to the National Electricity Objective and the requirements of the National Electricity Rules. This determination will be made against a background of very significant change, and this will challenge the AER accordingly.

From SA Power Networks' perspective, we believe that our Proposal can most simply be summarised as follows:

- SA Power Networks has a long record of effective, balanced performance, and is a high-performing DNSP. We aim to be reliable, safe, prudent and efficient in all that we do, and we believe we are a leader in our industry on all key dimensions.
- Our customers and our industry are changing. Our challenge is to continue delivering our services, and to adapt as circumstances demand, in order to continue to deliver value to our customers and stakeholders.
- We have considered these changes deeply, and we have gained a high level of customer and stakeholder insight and support through our engagement programs.
- On this basis, we have set appropriate balanced objectives and then developed a comprehensive Proposal that will deliver on the short and long term needs of our customers and stakeholders in an optimal way.
- We can deliver on these needs with a price path that will remain below CPI, consistent with the pricing expectation we clearly established in our customer engagement. Customers indicated that they valued our proposed programs of work, providing this price outcome could be met.

We consider this Proposal represents an appropriate balance of price and service that will meet the needs of South Australian customers and the wider community, and position us for sustained service delivery into the long term.

2.9

Key elements of our Regulatory Proposal

Table 2.5: Principal elements of SA Power Networks' Regulatory Proposal

Standard Control Services $M, June 2015	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Capital expenditure forecast	463.6	508.3	510.4	517.8	485.4	**2,485.5**
Regulatory Asset Base (close of period)	4,074.4	4,337.4	4,575.1	4,794.3	4,957.9	
Revenue requirements						
Return on capital (WACC 7.62%)	284.7	302.9	322.5	340.1	356.4	**1,606.6**
Return of capital	129.0	153.4	174.9	194.9	210.1	**862.2**
Operating expenditure	285.7	298.9	315.9	324.5	329.1	**1,554.1**
Carryover amounts	10.1	16.3	0.1	(12.6)	-	**13.9**
Net shared assets cost reduction	(0.8)	(0.8)	(0.8)	-	-	**(2.3)**
Tax (Gamma 0.25)	74.4	74.9	76.3	78.8	80.5	**384.9**
Annual revenue requirement (ARR)	**783.0**	**845.6**	**888.9**	**925.8**	**976.2**	**4,419.5**
Forecast energy consumption (GWh)	10,510	10,530	10,467	10,447	10,430	**52,384**
Control mechanism X factor (%)						
AER standard smoothing						
Smoothed revenue	795.9	837.6	881.4	927.6	976.2	**4,418.6**
Price Path	-13.4%	5.2%	5.2%	5.2%	5.2%	
SA Power Networks' proposed smoothing (Transitional Rule)						
Smoothed revenue	879.4	879.4	879.4	879.4	879.4	**4,396.9**
Price Path	-4.3%	0.0%	0.0%	0.0%	0.0%	
Alternative Control Services $M, June 2015	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**Total**
ARR	25.7	27.5	40.1	42.3	44.0	**179.6**
SA Power Networks Revenue Path	30.0	32.6	35.8	38.5	41.6	**178.5**
Control mechanism arrangements						
SCS subject to Revenue Cap						
ACS subject to Price Cap						
Jurisdictional service standards						
Reliability — targets for interruption duration and frequency based on historical average performance, for four standard feeder categories, excluding Major Event Days						
Customer service — targets for telephone and written enquiries responsiveness						
Reporting — reliability reported annually for seven geographic areas nominated by jurisdictional regulator, and for low-reliability feeders						
Guaranteed Service Level payments — for reliability (including during Major Event Days), appointment and connections timeliness, and street light repairs						
Incentive mechanisms						
Service Target Performance Incentive Scheme — applying to reliability and contact centre performance						
Efficiency Benefit Sharing Scheme — allowing operating efficiencies achieved in controllable cost categories to be retained for five years						
Capital Efficiency Sharing Scheme — which provides an incentive for outperformance of capital expenditure forecasts						
Ex-post measures for efficient capital expenditure — applying penalties where capital expenditure forecasts are exceeded and the expenditure is deemed inefficient						
Shared asset scheme — allows for a reduction in regulated revenue where an asset is used to provide both SCS and unregulated services						
Demand Management Incentive Scheme — which provides an allowance to investigate and conduct broad-based and/or peak demand management projects						
Proposed pass-through events (in addition to those defined in Chapter 6 of the NER)						
• Kangaroo Island cable failure event • Natural disaster event • Liability above insurance cap event • Insurer credit risk event • Native title event • General nominated pass through event						
Negotiated distribution services						
Subject to SA Power Networks' Negotiating Framework						

3
Business overview

3

This chapter provides an overview of SA Power Networks' role, network, customers, ownership, structure, and governance.

3.1

SA Power Networks' role

SA Power Networks is a key part of the fabric of the South Australian economy and community. We have proudly served South Australians for almost 70 years, initially as part of the Electricity Trust of South Australia, and then as a stand-alone distribution business established in the late 1990s when the electricity supply industry was transformed by a new regulatory framework.

As the local Distribution Network Service Provider (**DNSP**) our primary responsibility is planning, building, operating and maintaining the South Australian electricity distribution network — a strategic community asset and core component of the State's energy infrastructure. We do this in a safe, reliable, efficient and prudent manner.

Our business is about connecting residential and business customers to a safe and reliable electricity supply. SA Power Networks' key distribution activities include:

- maintaining the network's safety and reliability to meet the current power supply needs of our customers;
- extending and upgrading the network so that the future power supply needs of customers are met when required;
- operating the network on a day to day basis;
- connecting new customers to the network;
- maintaining the public lighting system;
- reading electricity meters; and
- providing meter data to retailers.

With the rapid take-up of solar PV by small customers, we increasingly facilitate the integration of small scale generation into our network, essentially providing a means for small customers to participate in the market. This role will increase as customers adopt a wider range of 'distributed energy resources' (**DER**) (eg battery storage and electric vehicles) in the coming years.

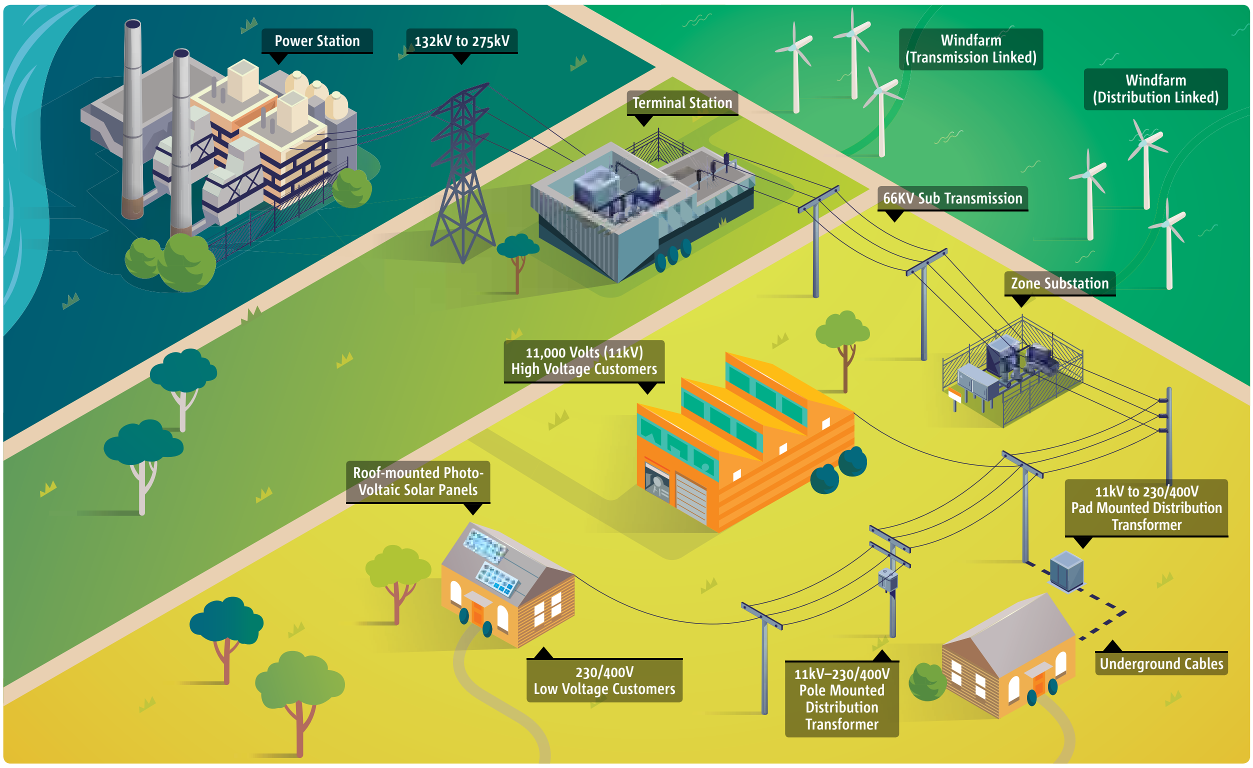
3.2

The South Australian distribution network — a vast and complex system

In the National Electricity Market (**NEM**), generators (either fossil fuelled or renewable) produce electricity, which is transported at high voltage across the transmission network (operated by ElectraNet in South Australia), to about 50 transmission network 'exit points' in or near urban and rural centres.

SA Power Networks then delivers electricity from the transmission system exit points to customers across the State from Ceduna to Mt Gambier. Retailers sell electricity to customers, having purchased it from the NEM wholesale market. They pay SA Power Networks (and ElectraNet) for use of the networks that deliver electricity to customers.

Figure 3.1: The South Australian electricity supply chain



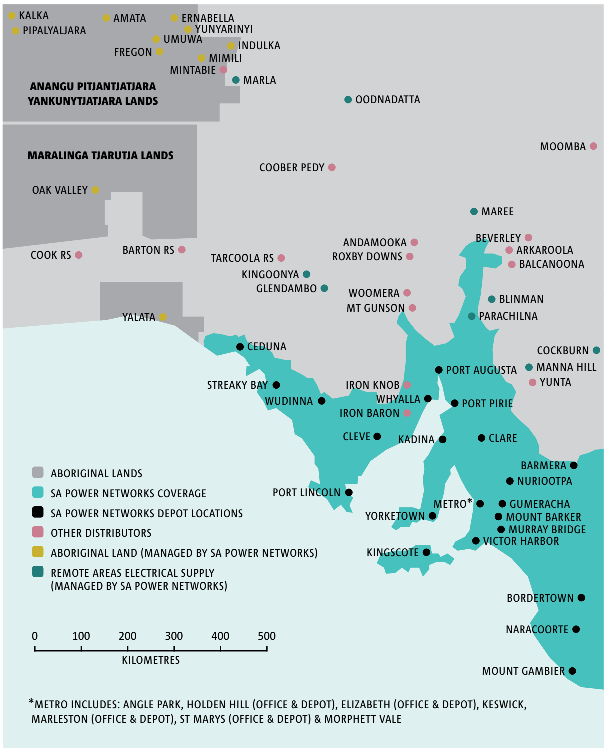
Generation | Transmission Network | Distribution Network

SOURCE: SA POWER NETWORKS

The electricity distribution network in South Australia is vast and complex, covering more than 178,000 km^2 along a coastline of over 5,000 km. The network extends across difficult and remote terrain and operates in demanding conditions and stretches for 88,000 km, and includes 400 zone substations, 73,000 street transformers, more than 720,000 stobie poles and 200,000 km of wires. Our assets also include circuit breakers, switches, meters, and a multitude of ancillary systems as well as fleet and depot facilities spread across the State.

We supply electricity to more than 840,000 customers ranging from isolated farms in rural areas to industry precincts, regional and metropolitan residential homes, businesses and city centres. Around 70% of the network is required to serve 30% of customers who live outside the Adelaide Metropolitan area. As a result, the average customer density per kilometre of line across the State is the lowest in the NEM.

Figure 3.2: SA Power Networks' service area and operational facilities



SOURCE: SA POWER NETWORKS

3.3

Our customers and their energy use

From July 2013 to June 2014 SA Power Networks' customers consumed 10,651 gigawatt hours (**GWh**) of electricity from our network with a distribution system Peak Demand of 3,120 megawatts (**MW**).

As at 30 June 2014 we were providing distribution services to 743,918 residential, 99,180 business and 23 major business customers totalling 843,121 customers. The significant majority of our customers are located in the major metropolitan areas.

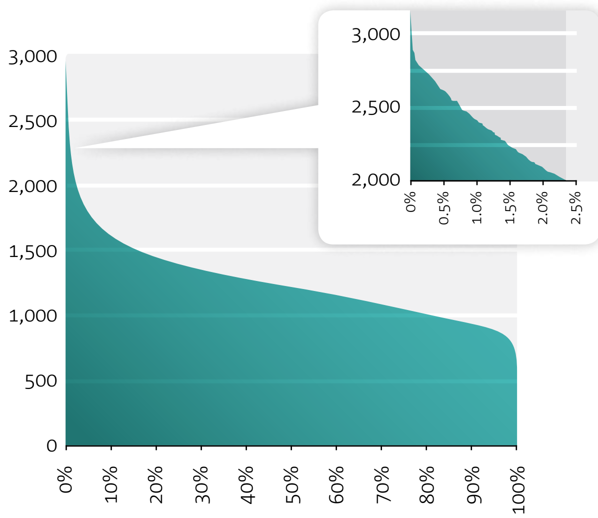
Table 3.1: Customers and consumption by geographic region

Electricity Distribution Code Regions	Customers by region	Electricity Consumption by region
Adelaide Business Area	0.3%	5.2%
Barossa/Mid North, Yorke Peninsula, Riverland and Murraylands	12.2%	11.9%
Eastern Hills/Fleurieu Peninsula	7.5%	4.6%
Kangaroo Island	0.5%	0.3%
Major Metropolitan Areas*	71.4%	67.4%
South East	3.4%	5.2%
Upper North and Eyre Peninsula	4.7%	5.4%
	100%	**100%**

* Major Metropolitan Areas (including: Adelaide metropolitan area, Mount Barker, Mount Gambier, Port Augusta, Port Lincoln and Whyalla).

South Australia has one of the peakiest electricity demand profiles in the world. In the few extremely hot days of a South Australian summer, typically around six to nine days each year, South Australia's electricity demand doubles relative to average demand levels on mild days. SA Power Networks is required to build infrastructure to meet the peak demand that occurs less than 2% of the year (refer Figure 3.3).

Figure 3.3: South Australia's total electricity system demand (MW)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

3.4

What makes up customers' electricity bills

Since 1999/2000 SA Power Networks' distribution cost portion of the average residential electricity bill has reduced from around 50% to 35% in 2014/15. Currently, distribution costs account for around 31% on average for small business customers and 34% on average for large business customers.

Table 3.2: Composition of average electricity bill in 2014/15

Electricity bill component	2014/15 Average 5MWh 'residential' electricity customer	2014/15 Average 'small business' electricity customer 20MWh	2014/15 Average 'large business' electricity customer 1000MWh
Average annual bill	$1,933	$7,154	$210,000
Energy*	40%	43%	36%
Distribution	35%	31%	34%
GST	9%	9%	9%
Transmission	7%	8%	12%
Solar PV feed-in tariff	6%	6%	6%
Carbon tax	3%	3%	3%
Total	**100%**	**100%**	**100%**

*Includes Renewable energy charges.

SOURCE: SA POWER NETWORKS ANALYSIS 2014

3.5

Our ownership and governance arrangements

SA Power Networks is a limited liability partnership which is 51 percent owned by Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited, which form part of the Cheung Kong Group of companies based in Hong Kong. The remaining 49 percent of the partnership is owned by Spark Infrastructure Group, a publicly listed infrastructure fund in which Cheung Kong Infrastructure has a small direct interest (9 percent). Spark commenced trading on the Australian Stock Exchange in December 2005.

Under the Partnership Agreement, the partners delegate responsibility to the Board of Directors for the operation of the business. The partners have also established a separate company, Utilities Management Pty Ltd, to act as agent of the partnership, engage the employees of the SA Power Networks business and provide general services to the partnership.

3.6

Our organisation

SA Power Networks' organisational structure is almost entirely geared towards our regulated distribution network roles and activities, with the exception of the ring-fenced Construction & Maintenance Services department which provides competitive services to commercial customers. The most significant of these customers is ElectraNet SA, the South Australian transmission network service provider, for whom SA Power Networks undertakes maintenance services and capital works.

Figure 3.4: SA Power Networks' organisational structure (as at 3 September 2014)

Chief Executive Officer

GM Network Management
- Network Investment Strategy & Planning
- Network Asset Management
- Network Standards & Performance
- Network Planning
- Network Control
- Customer Solutions

GM Field Services
- Power line Operations
- Substation & Transmission Construction
- Major Project Management
- Vegetation Management
- Procurement
- Supply Chain Management
- Design Services
- Business Improvement

GM Customer Relations
- Revenue Services
- Meter Data Management
- Retailer Relations
- Business Improvement & Planning
- NEM Operational Regulatory Management
- Data Quality (Customer)
- Customer Insight & Consultation
- Customer Response
- Connection Services
- Key Stakeholder Relations

GM People & Culture
- Human Relations
- Learning & Development
- Organisational Change
- Occupational Health & Safety
- Environmental Management
- Property Services

Company Secretary
- Company Secretary
- Risk
- Insurance
- Legal
- Real Estate & Easements

Chief Financial Officer (CFO)
- Financial Planning & Budgeting
- Financial Reporting
- Financial Control
- Taxation
- Treasury
- Accounts Receivable
- Accounts Payable
- Fleet Management

Chief Information Officer (CIO)
- Information Technology
- Information & System Security

GM Corporate Strategy
- Regulation
- Strategic Planning
- Quality Management
- Enterprise Architecture
- Corporate Portfolio Management Office
- Innovation

Office of the CEO
- Audit Services
- Corporate Communications
- Sponsorships

GM Construction & Maintenance Services
- Unregulated Customer Services
- Substation Construction & Maintenance
- Transmission & Distribution Line Construction & Maintenance
- ElectraNet Services
- Material Sales
- Telecoms Construction & Maintenance
- NBN Construction
- National Operations
- Business & Strategic Development

SOURCE: SA POWER NETWORKS 2014

3.7

Prudently driving cost efficiencies across our business

SA Power Networks is committed to the highest standards of Corporate Governance, and operates under a robust Corporate Governance Framework (**CGF**) that ensures achievement of the best balance of outcomes for customers, employees, the community and shareholders.

On behalf of the SA Power Networks Partnership, the Board has been delegated responsibility for the overall corporate governance of the business including critical responsibilities of strategy setting, policy definition and compliance, and monitoring business performance.

The key elements of the CGF are:

- **SA Power Networks Board** — the body representing the Partners responsible for the conduct of the SA Power Networks business and strategic direction;
- **Board Sub-Committees** — bodies established under the Partnership Agreement to assist the Board;
- **Business Plan** — what SA Power Networks is aiming to achieve;
- **Policies** — the intended manner by which SA Power Networks will achieve the Business Plan;
- **Delegations of Authority** — authorities delegated by the Board to SA Power Networks officers to enable day to day conduct of the business;
- **Performance Management** — the process of monitoring by the Board to ensure the Business Plan is achieved; and
- **Assurance** — providing assurance to the Board that SA Power Networks is achieving its objectives, as per the Plan, in the manner intended.

The Board-approved Policies are regularly reviewed, widely communicated throughout the business, and provide a robust platform of strategic principles that guide operational activities supported by the implementation of comprehensive procedures, plans and guidelines.
Key policies include:

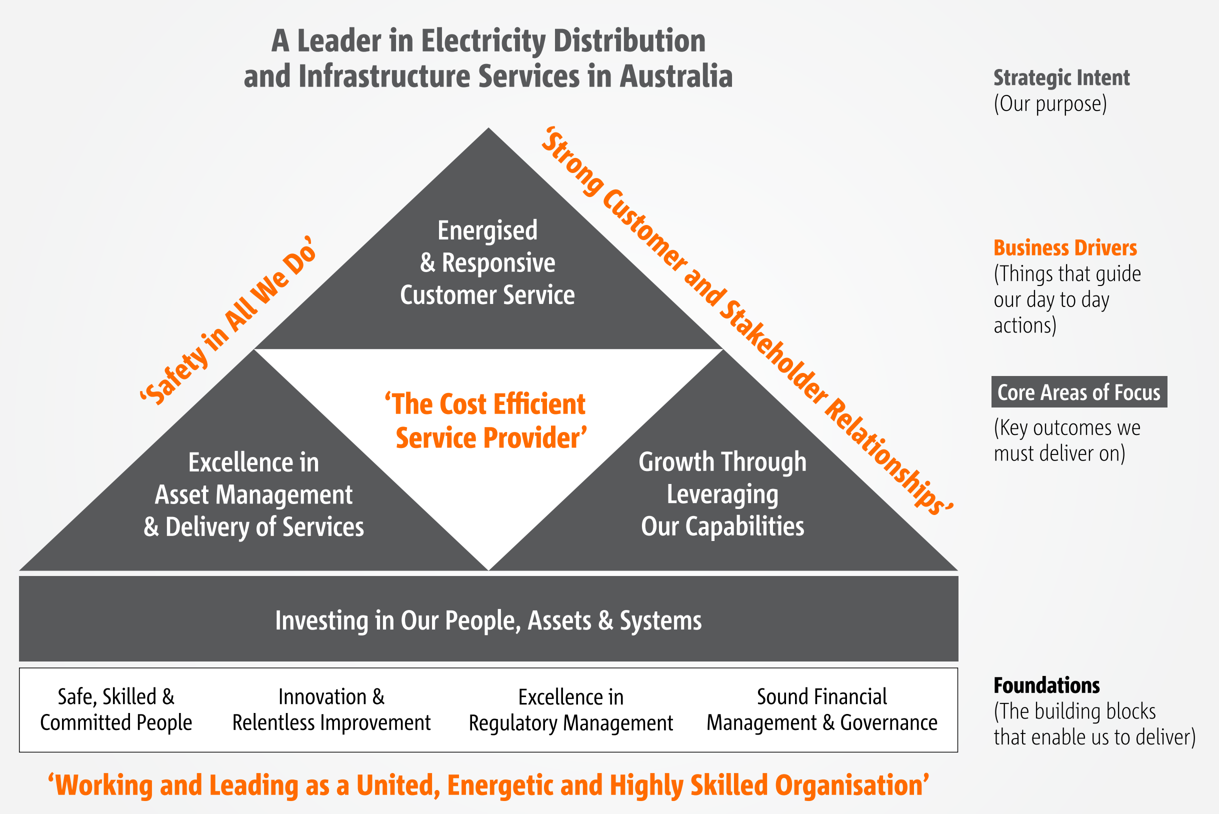
- **Asset Management policy** — requires SA Power Networks to manage the network assets to satisfy customer service needs, to meet Licence and Regulatory obligations, to provide a safe environment for employees, contractors and the community, and to deliver a commercial return to shareholders. This is done by employing good industry asset management practice to manage the life cycle of assets prudently and efficiently, and to ensure long term sustainable performance and condition of the assets.
- **Customer Service policy** — to provide our customers with services which are targeted to their needs and expectations and delivered in a way which reinforces their prime importance to our business.
- **Environmental policy** — to conduct our operations and business activities in a manner that prevents or minimises pollution and other adverse impacts on the environment and ensures we meet our environmental legal obligations.
- **Compliance policy** — to ensure SA Power Networks conducts its business activities in compliance with all relevant legal, regulatory and contractual obligations and requirements of relevant standards and internal policies (including directives, procedures and instructions).
- **Risk Management policy** — requires SA Power Networks to apply a risk management approach to all business activities in order to ensure that the organisation maximises opportunities while not exposing the business to unacceptable levels of risk.

Our business plans are conceived, prepared and implemented according to a robust corporate strategic framework (see Figure 3.5). The framework reflects our business objectives, strategies, and philosophies. It ensures that all employees have a clear understanding of the business' Strategic Intent, the values that we seek to foster in all employees, the balance of outcomes that are expected for customers, the community, employees and shareholders, and the array of core business outcomes and capabilities which will allow SA Power Networks to achieve its strategic intent.

Among other things, the framework reflects:

- an urgency and the energy that shapes our culture and maintains the momentum of positive change;
- strong business drivers that emphasise safety, a 'One-Business' philosophy, attention to key external and internal relationships, and over-riding recognition that we need to continue to be cost efficient in all that we do;
- the need to integrate and streamline our activities across the asset management and field delivery groups;
- that customer service is as much about being responsive and providing timely and useful information to customers as it is about reliability and supply restoration; and
- that ongoing prudent investment in our people, assets and systems is key to a sustainable business.

Figure 3.5: SA Power Networks' strategic framework



SOURCE: SA POWER NETWORKS 2014

4
Our track record

4

SA Power Networks takes pride in its strong, balanced performance over a long period of time. We have delivered on key outcomes for all our stakeholders, and have done so from a position as the most efficient distributor in the NEM.

For our customers, SA Power Networks has:
- prudently and efficiently delivered network services;
- achieved all the key regulated service targets;
- improved the service experience for customers;
- introduced new service channels such as self-service applications for customers (eg Power@MyPlace) and electricians (online connections booking system); and
- worked hard to improve communication and engagement with all stakeholders.

For the community, SA Power Networks has:
- continued to be a good and ethical corporate citizen;
- continued to be a major employer across the State, with over 90% growth in jobs since 1999;
- complied with all environmental obligations;
- implemented programs that minimise the organisation's environmental footprint; and
- implemented one of our State's largest community engagement programs.

For our employees, SA Power Networks has:
- achieved exceptional safety outcomes;
- maintained a fair and rewarding workplace for employees;
- provided excellent training and development opportunities; and
- established an employee foundation (employees have raised $1 million for charity over the last seven years).

For our shareholders, SA Power Networks has:
- managed high risks;
- delivered acceptable returns;
- maintained business value; and
- maintained strong governance systems.

4.1

One of Australia's most reliable networks

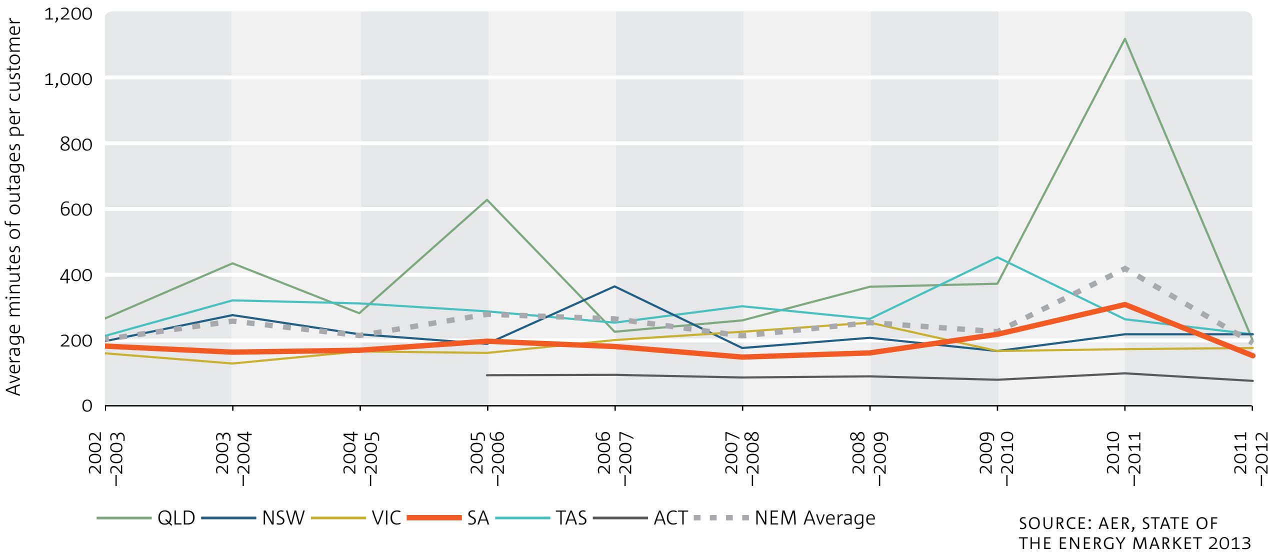
As outlined in Figure 4.1 South Australians have enjoyed the benefits of one of the most reliable distribution systems in Australia over a long period of time (measured in the average number of minutes of power interruptions experienced by customers per year). Continuing this focus on delivering a reliable and safe power supply for South Australians is one of SA Power Networks' most important objectives.

Notwithstanding this, the impact of extraordinary weather events, including extreme lightning, wind, and heatwave conditions, affect the network's reliability, making it challenging to consistently deliver the level of reliability expected by our customers. Figure 4.2 shows our State-wide average historical reliability target, overall reliability performance and underlying reliability performance (after removing the impacts of severe weather events). Whilst over the last four years South Australia has experienced an increased number of severe weather events, the underlying reliability performance has remained stable.

Our performance in managing these severe weather events is reviewed by ESCoSA which has confirmed that SA Power Networks has complied with its reliability service standard obligations and that we have responded effectively to severe weather events.

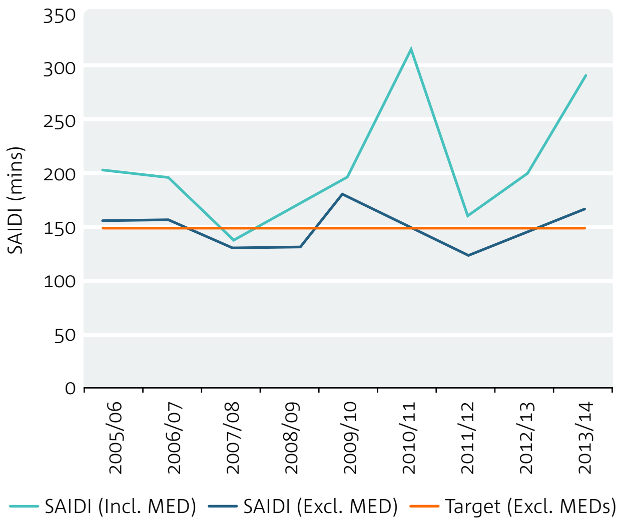
We are also subject to the AER's Service Target Performance Incentive Scheme (**STPIS**) which provides financial rewards and penalties for distribution businesses depending on their performance against reliability and customer service targets with the major portion of the scheme focussed on reliability. Figure 4.3 highlights the STPIS outcome from each regulatory year's performance in terms of percentage of revenue. The 2013/14 performance arose from some of the most intense severe weather events on record.

Figure 4.1: Australia-wide distribution network performance — system reliability



SOURCE: AER, STATE OF THE ENERGY MARKET 2013

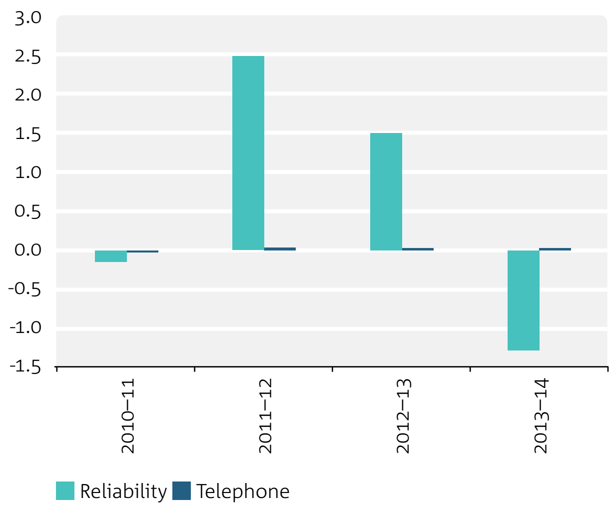
Figure 4.2: Annual network reliability performance with and without impact of severe weather events (Major Event Days)



Note: SAIDI is System Average Interruption Duration Index. It equates to the average number of minutes a customer experiences loss of supply due to unplanned interruptions per year.

SOURCE: SA POWER NETWORKS ANALYSIS 2014

Figure 4.3: SA Power Networks STPIS outcomes 2010–2014 (% Rev)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

4.2

Continued focus on being the most efficient distributor in the NEM

SA Power Networks has achieved balanced outcomes for customers, the community, employees and shareholders while being at the forefront of economic efficiency amongst Australian electricity distributors. This has delivered value to customers as evidenced by the reducing distribution portion of electricity bills.

4.2.1 Industry benchmarking

Recent changes to the NER have affirmed the role of economic benchmarking as a key factor in the AER determining the efficiency of DNSP expenditure forecasts. The NER now require the AER to publish benchmarking reports annually[1] and the AER must have regard to this in its assessment of operating and capital expenditure forecasts of DNSPs[2]. Multilateral Total Factor Productivity (**MTFP**), Data Envelopment Analysis (**DEA**) and econometric modelling have each been identified by the AER as benchmarking techniques that it is likely it will use. The NER specifies that the AER's inaugural Annual Benchmarking Report be released by 30 September 2014. The AER has now advised that this report will be released in November 2014 and as a consequence its findings have not been available for assessment nor taken into account in this Proposal.

Notwithstanding the AER's deferral of its report, SA Power Networks has engaged expert consultants Huegin Consulting (**Huegin**) to conduct preliminary modelling to measure SA Power Networks' efficiency relative to other DNSPs in the NEM. Huegin has based its analysis on the AER's preferred model specification of MTFP and DEA, as outlined in the AER's Explanatory Statement to the Expenditure Forecast Assessment Guideline[3]. At this time, econometric model specifications are purely speculative and as such, have not been included in Huegin's analysis.

The AER is proposing to use benchmarking results:

- as part of its 'first pass' assessment of DNSP expenditure; and
- to review the relative efficiency of historic DNSP expenditure and the suitability of base year expenditure to be extrapolated into the future.

The AER has indicated that DEA results could be used to cross check the results generated by the MTFP model.

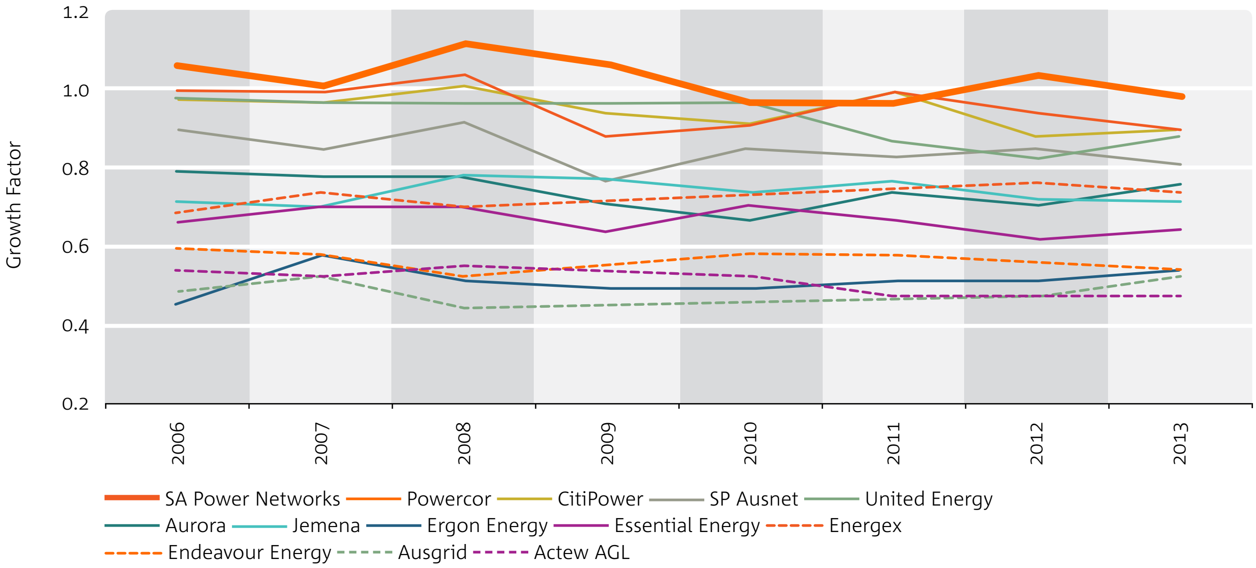
1 NER, Clause 6.27
2 NER, Clauses 6.5.6(e) and 6.5.7(e).
3 AER, 'Expenditure Forecast Assessment Guideline: Explanatory Statement', Nov 2013, p. 151.

In its analysis, Huegin has applied the methodology proposed by the AER's Regulatory Development Branch[4] and adjusted MTFP results for the most significant operating environment factor, in this case being customer density, using an approach undertaken by the AER's consultant, Economic Insights[5]. This is consistent with the AER's view that:

"We consider density variables are the most important environmental factors that may affect DNSPs' costs. A DNSP with lower customer density is likely to require more network assets to service the same number of customers, for example, than does a higher density DNSP. Since the lower density DNSP will require more inputs to produce the same level of outputs, it will appear to be inefficient relative to the higher density DNSP. Some adjustment for the impact is therefore required."[6]

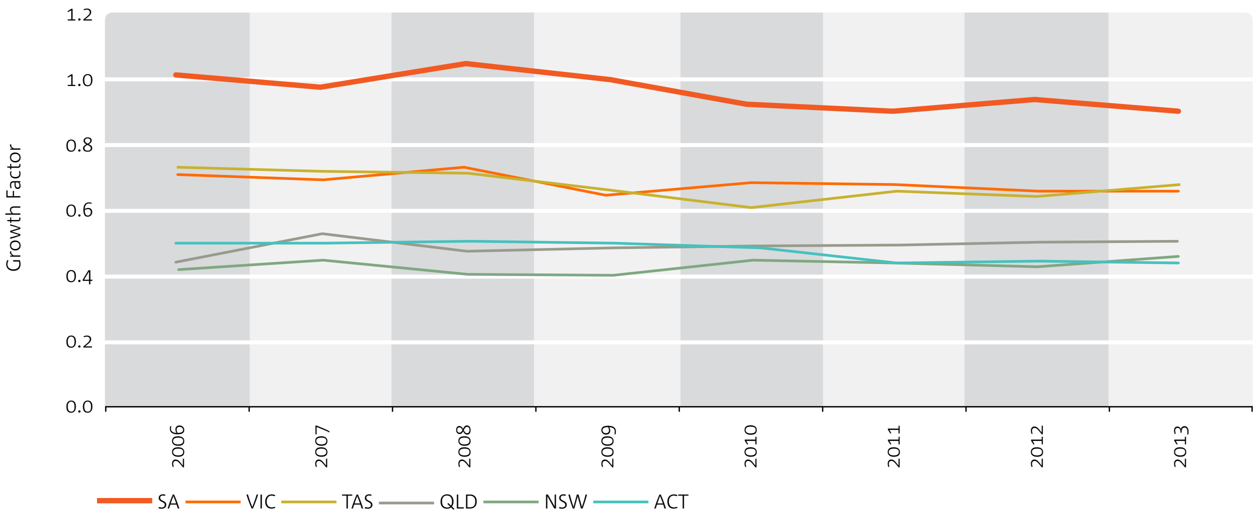
Huegin's results indicate that SA Power Networks is the most efficient DNSP in the NEM (see Figure 4.4 and 4.5). Further detail regarding Huegin's analysis is contained in Attachment 4.1.

Figure 4.4: Multilateral total factor productivity for each NEM DNSP, based on the AER's preferred MTFP model specification



SOURCE: HUEGIN (ATTACHMENT 4.1,), BASED ON ECONOMIC BENCHMARKING RIN DATA RELEASED BY THE AER, 2014

Figure 4.5: State-wide multilateral total factor productivity



SOURCE: HUEGIN (ATTACHMENT 4.1,), BASED ON ECONOMIC BENCHMARKING RIN DATA RELEASED BY THE AER, 2014

4 AER (Regulatory Development Branch), 'Economic Benchmarking Model: Technical Report', p. 5.

5 Economic Insights, 'International Benchmarking of Postal Service Productivity' (report prepared for Australia Post), June 2009.

6 AER, 'Expenditure Forecast Assessment Guideline: Explanatory Statement', Nov 2013, p. 160.

Huegin has also provided MTFP results on a state-wide basis, that shows South Australia (and hence, SA Power Networks) as the most efficient state in the NEM. At a state-wide level, the comparison is based on a broader geographical area and hence normalises the varying operating environment factors across DNSPs to some extent. Huegin's results also indicate that across the industry, productivity has been declining over time. This should not be inferred as evidence of declining efficiency.

This trend has also been observed by the Productivity Commission, who has identified a range of factors impacting on the productivity of the electricity supply industry in Australia[7], and may be reflective of rising input costs in a period of plateauing output measures. Notwithstanding our position as the most efficient network business, we have sought to understand specific underlying factors that may be influencing the downward trend in MTFP results as an integral part of our continued focus on improving the way we do business. We have identified a number of specific factors that, since 2010, have been either increasing our inputs or decreasing our outputs and are uncontrollable by SA Power Networks. These factors, which are detailed below, negatively impact on SA Power Networks' MTFP result, and are detailed below:

- vegetation management: vegetation management costs have doubled with the breaking of the 'millennium drought' in 2010 and the subsequent rapid growth in vegetation and resulting clearance infringements around power lines. These additional input costs have been and continue to be incurred to ensure community safety but do not increase MTFP outputs.
- reliability guaranteed service level (**GSL**) payments: During the current regulatory control period (**RCP**), there has been a significant increase in the severity of major weather events (storms, lightning and high winds). The payments made to customers for the inconvenience of loss of supply for the first four years of the current RCP are nearly quadruple the level of the five years of the previous RCP. The effect of these severe weather events increases the input costs in the MTFP analysis and also has a negative impact on outputs through increased customer interruptions.

The above benchmarking information supports the assessment that SA Power Networks is an industry leader in economic efficiency. SA Power Networks supports the use of benchmarking to inform the AER's consideration of DNSPs' regulatory proposals, rather than as a starting point for assessing DNSPs' regulatory proposals and applying the outcomes deterministically.

4.2.2 Maintaining efficiency leadership

SA Power Networks continues to focus on ways to manage the transformational change occurring within the energy industry and to maintain our leadership in cost efficiency. To meet this challenge, innovation and continuous improvement are a key priority for the business and there is a growing organisational emphasis on innovation and process and quality management across all areas of the business. Examples include:

- developing and implementing new self-service applications for our customers (eg Power@MyPlace, self-service power outage and streetlight outage reporting, and our Registered Electricians Extranet System);
- establishment of our Network Innovation Centre which is focused on developing and trialling new network technologies and demand side participation initiatives so that we can continue delivering appropriate solutions for our customers now and in the future;
- visioning and articulating the many transformative technological impacts upon our customers and our business via development of our Future Operating Model 2028, which helps to communicate the key challenges and opportunities that will most likely shape the energy industry and SA Power Networks over the next 15 years; and
- establishing new business functions that will underpin the development of critical business capabilities for the future. These include responsibilities for enhanced quality governance and systems, innovation processes, business architecture and project, program and portfolio management

4.3 Prudent investment in our network

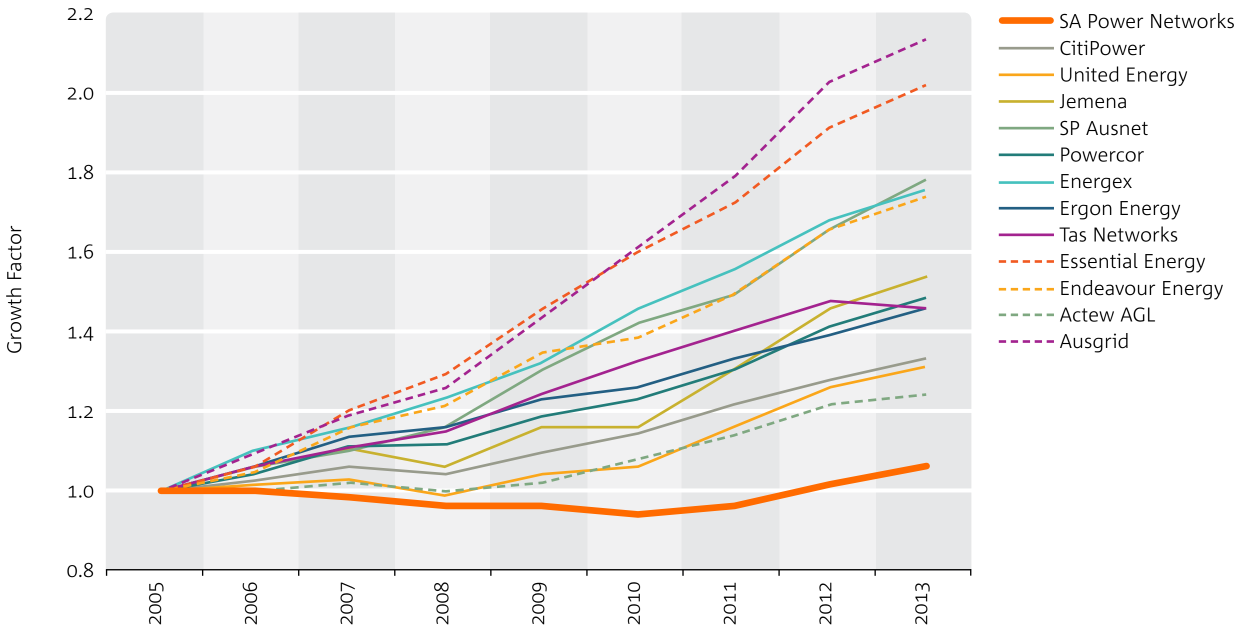
In recent times there has been substantial public commentary on the level of investment undertaken by network businesses across Australia with strong assertions that network businesses are "gold-plating" their networks.

Figure 4.7 shows the relative growth in the real values of regulatory asset bases (**RAB**). Since 2005 there has been limited growth in SA Power Networks' assets, providing a high level of confidence to customers that SA Power Networks has and will continue to be economically prudent when undertaking infrastructure investments.

The economic benchmarking combined with level of investments shows that SA Power Networks remains firmly as a leader of economic efficiency in the NEM, and South Australian customers can be assured that cost efficient and prudent performance will underpin SA Power Networks' proposals for the future.

7 Productivity Commission, 'PC Productivity Update 2014', April 2014, pp. 13–15.

Figure 4.7: Real RAB growth — NEM DNSPs



SOURCE: SA POWER NETWORKS ANALYSIS, BASED ON AER BENCHMARKING DATA 2014

4.4

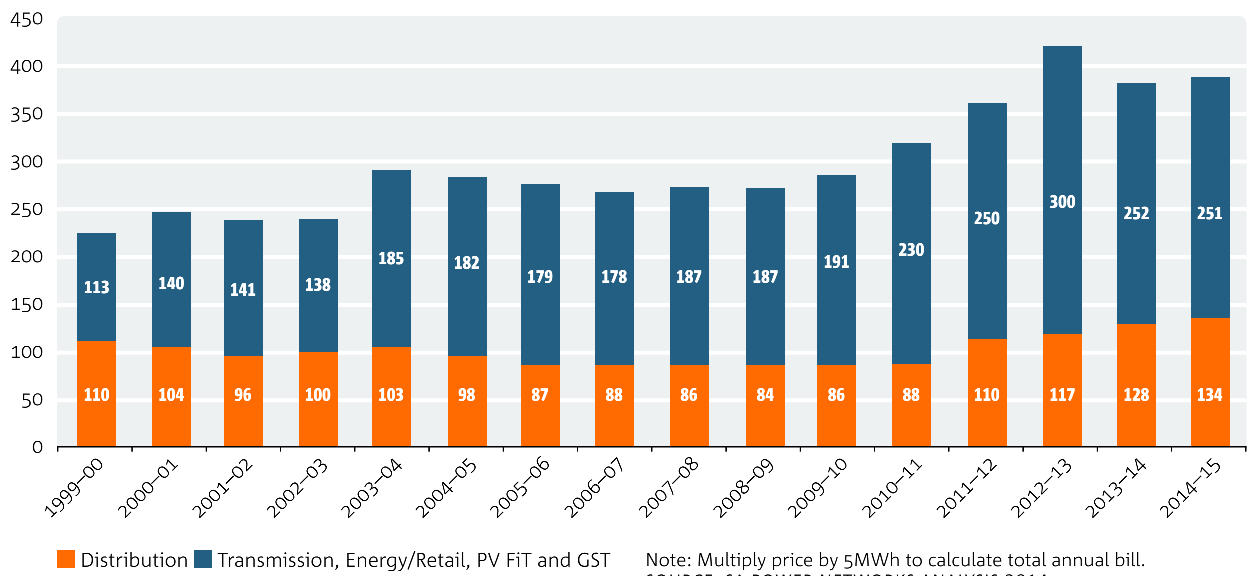
Delivering on an optimal service price mix

Whilst we continue to focus on cost efficiency, the prudent management of the network requires timely investment to meet customer needs. During the current RCP SA Power Networks has been investing in the network to deliver a safe, reliable and quality electricity supply and to improve service to our South Australian customers. In doing so, we need to manage customers' requests or new and upgraded connections, the maintenance of many assets that were built over 50 years ago, and the increasing penetration of large air-conditioners and solar PV panels in residential homes.

Notwithstanding the investment being made within the current RCP our share of the average electricity bill is now around one third, down from half in 1999/2000. The following figures show the historical trend in electricity prices since 1999/2000 for the average residential customer (5 MWh per annum) as well as the impact for small-medium businesses (10–100 MWh per annum) and large customers (1000 MWh per annum).

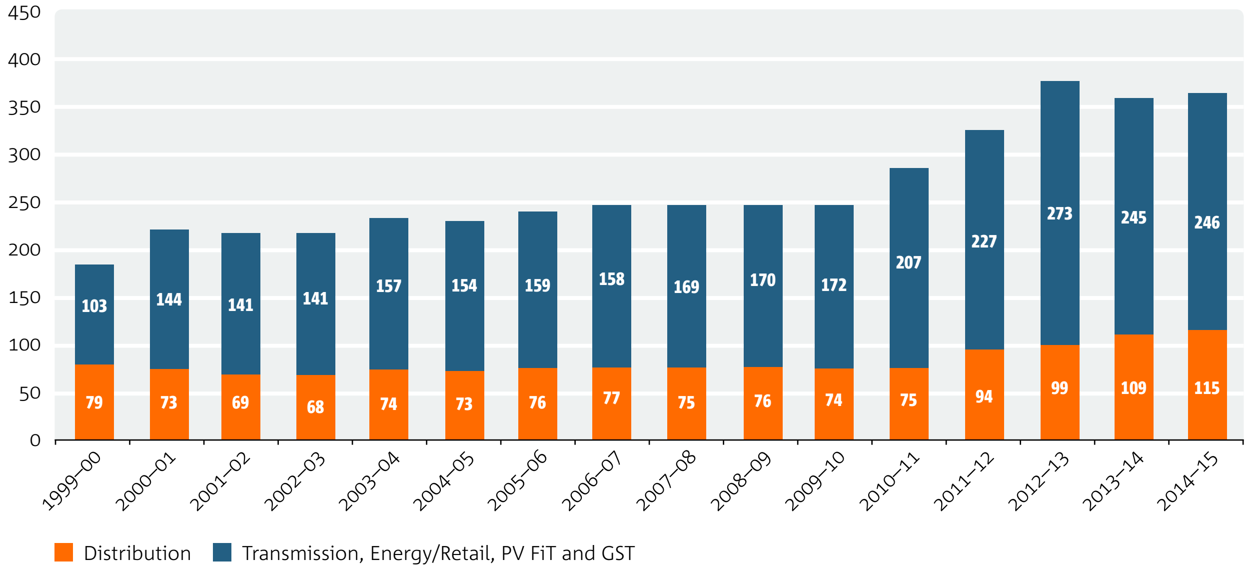
Between 1999/00 and 2014/15, SA Power Networks' distribution costs for the average 5MWh residential electricity customer accounted for only 15% of the increase in total electricity bills.

Figure 4.8: Change in average 5MWh pa residential electricity customer electricity bill price components (1999–2015) (All values in 2014/15 $/MWh)



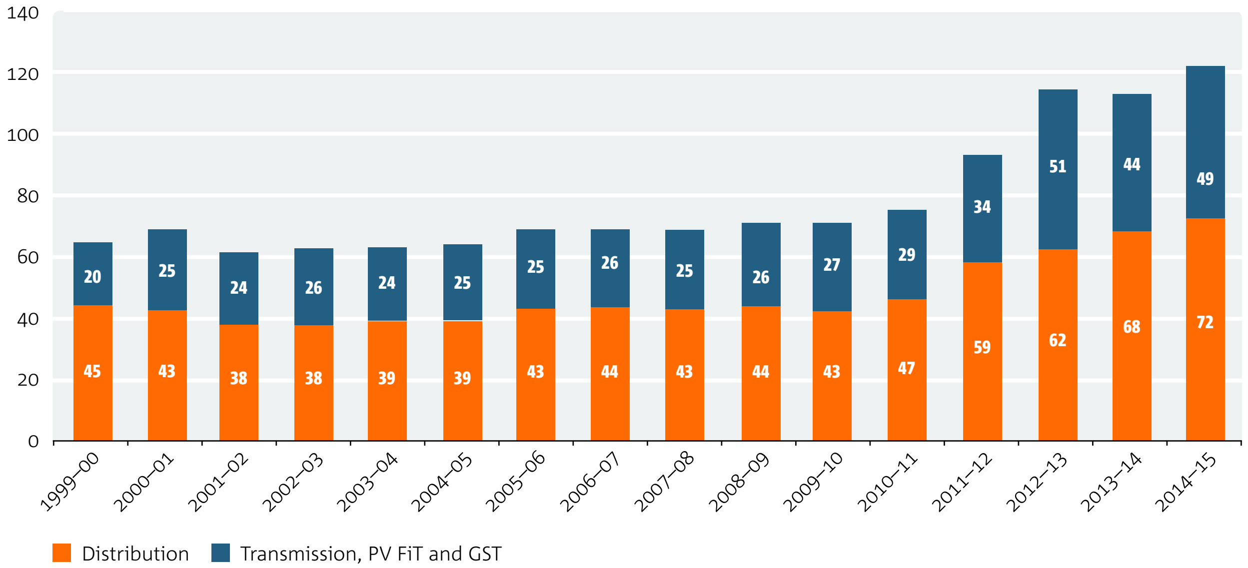
Note: Multiply price by 5MWh to calculate total annual bill.
SOURCE: SA POWER NETWORKS ANALYSIS 2014

Figure 4.9: Change in the typical small business electricity customer (10–100MWh pa) electricity bill price components (1999–2015) (All values in 2014/15 $/MWh)



Note: Multiply price by MWh pa to calculate total annual bill.
SOURCE: SA POWER NETWORKS ANALYSIS 2014

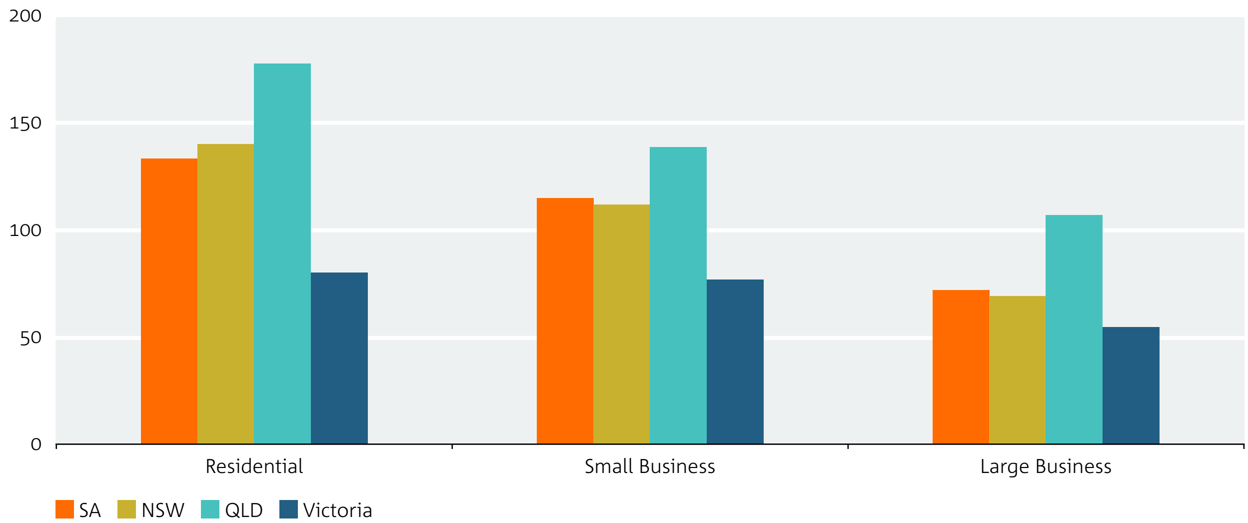
Figure 4.10: Change in the typical large business electricity customer (1,000 MWH pa) electricity bill price components — network only (1999–2015) (All values in 2014/15 $/MWh)



Note: Multiply price by MWh pa to calculate total annual bill.
SOURCE: SA POWER NETWORKS ANALYSIS 2014

A comparison of the distribution prices applying to each of these three customer segments across the principal states in the NEM has been prepared (see Figure 4.11). It shows the typical prices paid in July 2014 for distribution (including metering) services in Queensland, New South Wales, Victoria and South Australia. A simple average of the tariffs from the distributors operating in each of these states has been used. This approach enables state-wide distribution price outcomes to be compared.

Figure 4.11: Comparison of average Australian distribution prices (July 2014, excl. GST) (All values in 2014/15 $/MWh)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

The chart shows that SA Power Networks' distribution prices for each of the principal customer segments are competitive with those of other mainland states. The Victorian prices reflect (in part) the cost benefits of more urban and less rural networks (ie a higher population density). Victoria also has a lower penetration of air-conditioning at this time, resulting in less capacity requirements by customers.

South Australia shares with both New South Wales and Queensland the lower population density of extensive rural networks, plus the higher penetration of air-conditioning and, more recently, of solar PV systems. These factors have an upward impact on costs.

4.5

Delivering excellent levels of customer service and meeting customers' changing needs

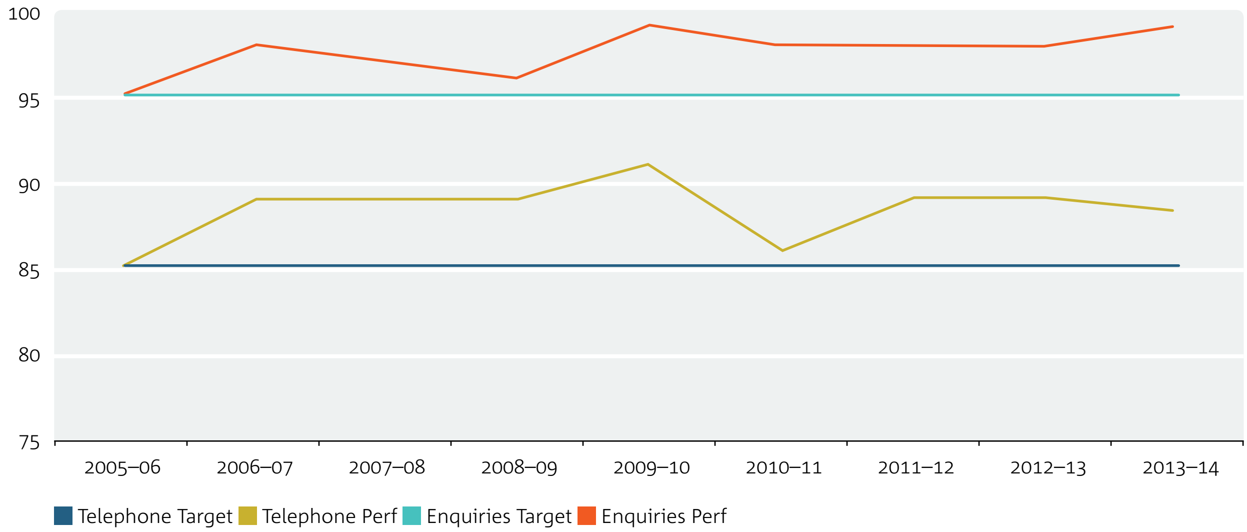
SA Power Networks has consistently out-performed regulated customer service standards over many years. ESCoSA establishes and monitors our performance against customer service standards related to our responsiveness to customer contact:

- 85% of telephone calls answered within 30 seconds; and
- 95% of customer enquiries addressed with a written response or acknowledgement within five business days.

Figure 4.12 highlights SA Power Networks' performance against those customer service standards.

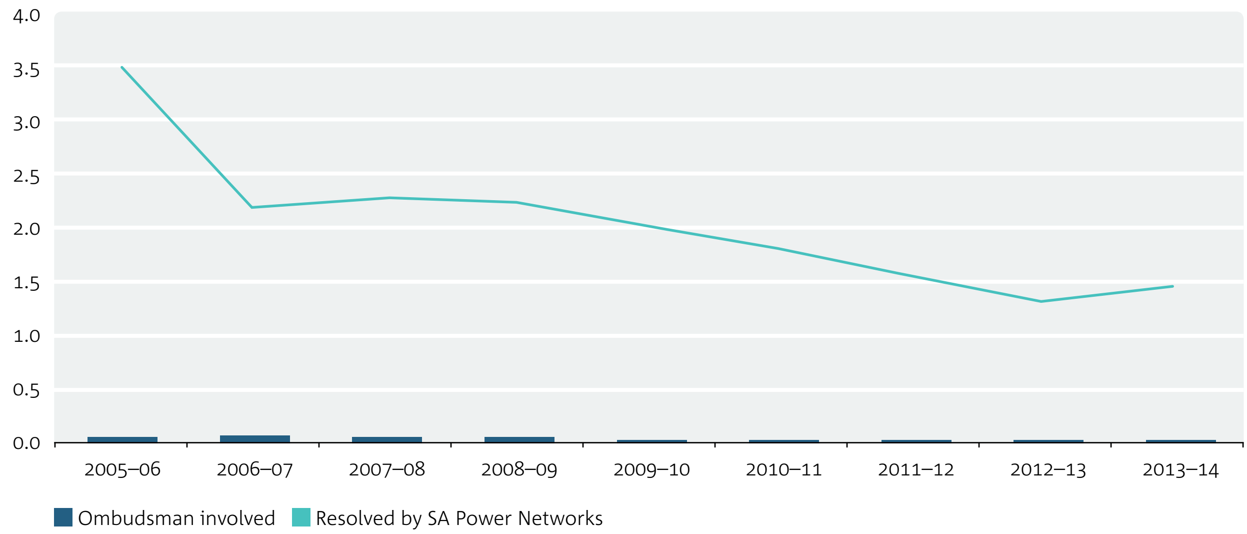
ESCoSA also monitors the number of customer complaints received by SA Power Networks (see Figure 4.13) which has progressively reduced over time.

Figure 4.12: SA Power Networks' customer service performance 2005–2013 (%)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Figure 4.13: SA Power Networks' customer complaints (per 1000 customers) 2005–2013
Customer complaints per 1,000 customers



SOURCE: SA POWER NETWORKS ANALYSIS 2014

We also regularly engage with our customers (through surveys and one on one engagement activities) to closely monitor our customers' satisfaction over a broad range of services. This allows us to gain valuable insight into what is important to our customers and allows us to identify and target specific areas in which we can improve the customer experience.

SA Power Networks' customer service capability has been recognised as delivering service excellence. Over the last five years we have been awarded multiple awards for our people and performance by the Customer Service' Institute of Australia. In 2012, SA Power Networks Customer Response team was State winner for the categories of Customer Service Executive of the Year, Customer Service Professional of the Year, Call Centre Manager of the Year, Customer Service Advocate of the Year, and Customer Service Division of a Large Business.

We continue to enhance the way we interact with and service our customers:

- we were the first Australian electricity distributor to offer online self-service fault reporting via internet and mobile devices — over 14,000 power outages have been reported by our customers online via 'Report a Power Outage';
- our customers are now also able to report streetlight faults via a convenient online map — over 79,500 streetlight outages reported via a Google map tool 'Report a Streetlight' since introduction in February 2012;
- 430% increase in unique visitors to the SA Power Networks website between 2008 and September 2014;
- 121,618 registered Power@MyPlace™ customers to whom we have sent over 525,014 text messages and emails related to power outages and over 197,931 SMS and emails related to meter reading;
- 12,727 Facebook Fans;
- 2,845 SA Power Networks Twitter followers; and
- 1,625 Registered Electrical Contractors registered to use our Registered Electricians Extranet System.

4.6

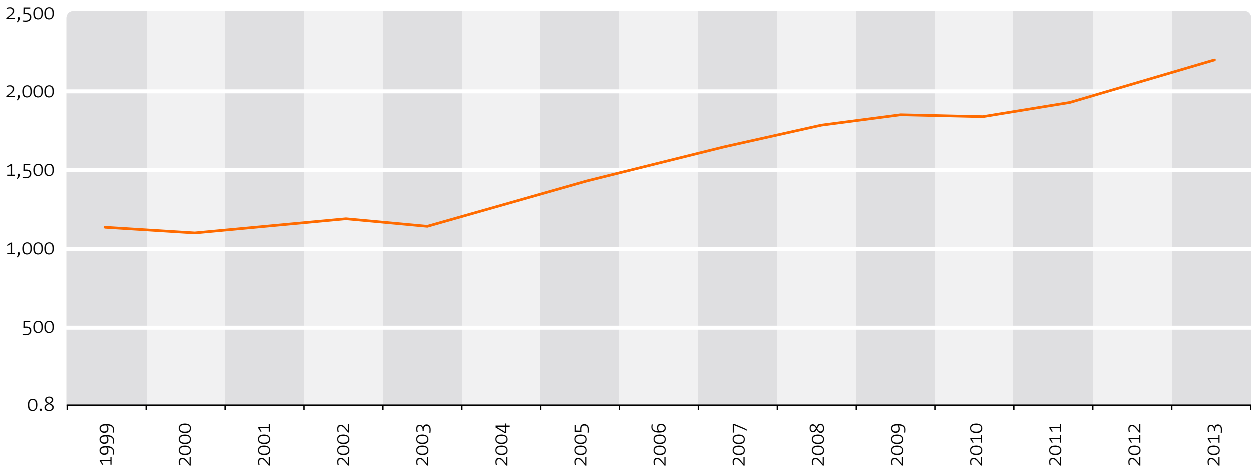
A caring, well respected and major South Australian employer

We are one of the largest South Australian employers, with a growing and committed workforce of over 2,200 employees, with around 200 additional workers engaged locally through labour contract arrangements.

Our people are our most important asset and our workforce helps ensure the sustainability of our business by developing the right mix of skills and resources to meet current and future needs. We have recruited 230 apprentices over the last six years with a greater than 90% retention rate. Our graduate, mentoring and leadership programs are well regarded by our employees and have achieved State, national and international recognition.

Historically the electricity industry has been inherently a male dominated workplace. SA Power Networks has implemented a range of strategies to increase the number of women in our workforce and support their development, advancement and success by creating a workplace that reflects the gender diversity of the broader community and where women and men feel empowered to achieve their full potential.

Figure 4.14: Major South Australian employer — Full Time Equivalent employees (1999–2013)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

We do not compromise on safety. It is embedded in our business' culture and values and it is our number one priority in terms of ensuring safe outcomes for our people, contractors, customers and the South Australian community. At the time of writing SA Power Networks has had no LTI for over 600 days. Importantly, it means our employees go home safe to their families.

SA Power Networks' workplace safety culture is based on the belief that all accidents are preventable and that no worker should suffer an injury or illness arising from work. Our safety performance has led our industry for many years and is reflected in Figures 4.15 and 4.16, which demonstrate excellent and improving outcomes.

Figure 4.15: Calendar Year Lost Time Injury Frequency Rate (**LTIFR**) (2004–2013)

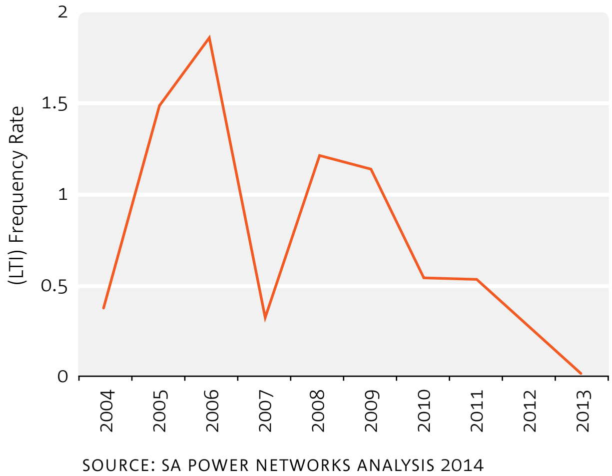
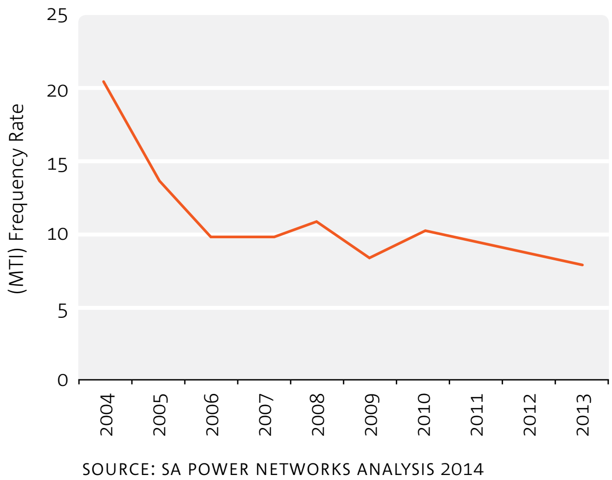


Figure 4.16: Calendar Year Medical Treatment Injury Frequency Rate (**MTIFR**) (2004–2013)



We continue to focus on providing our employees with the necessary facilities, vehicles and tools to ensure they are properly resourced to undertake their work efficiently and safely.

Our stakeholders also have a strong expectation that SA Power Networks will act responsibly and show leadership in environmental management. We have an excellent track record in environmental legislative compliance and continually seek out opportunities to further improve our performance in environmental management, and minimise the impact of our activities on the environment.

To ensure our environmental management objectives are met, we maintain a robust Environmental Management System in line with ISO14001, the industry benchmark, and an annually reviewed Environmental Management Plan, which provides direction for our managers and employees in delivering the intent of our Environmental Policy and Directives. For example, only 8% of the total waste generated by SA Power Networks is now sent to landfill — a huge improvement on the estimated 92% in 2009. Also, our electricity and gas consumption at our head office have reduced by more than 20% and 45% respectively over the last five years.

SA Power Networks has been a longstanding major contributor to the community in South Australia. Our community engagement activities include those of both our corporate sponsorship program and our Employee Foundation (**the Foundation**). Funding for our sponsorship program comes from our Owners and the Foundation raises funds from employee giving and fundraising activities, so neither of these programs form part of SA Power Networks' regulated costs.

The Foundation reflects our employees' determination to make a positive contribution to the lives of people in our community, through volunteering, fundraising and donating money, goods and services. Over the past seven years, our employees have raised $1 million for their chosen charitable causes which span areas including family support, homelessness, children and the environment. The sponsorship program works through a range of community partnerships to enable hundreds of thousands of South Australians to benefit from, or participate in, activities supported by our organisation. The wide scope of our community initiatives is evident in Table 4.1.

Table 4.1: SA Power Networks' community engagement initiatives

Employee Foundation causes	Sponsorship program partnerships
Appeals	Adelaide Bite (South Australia's baseball team)
Cancer Council SA	Adelaide Symphony Orchestra
Hutt Street Centre	Asthma SA
Mary Potter Foundation	Balls4Life (prostate cancer research)
Para Woodland Nature Reserve	Contax Netball Club
Uniting Care Wesley	Country Arts SA
Womens and Childrens Hospital Foundation	Graham Polly Farmer Foundation (indigenous youth education)
	Guide Dogs SA.NT
	Helpmann Academy (young artists)
	Mary Potter Hospice
	Operation Flinders (youth at risk)
	Starlight Children's Foundation
	Trees for Life

5 Our operating environment

5

There are a number of fundamental factors that influence the operations of SA Power Networks, from the vast and complex nature of our network, to the changing state of the South Australian economy, through to how customers wish to consume energy in the future. Underpinning this is the investment we need to make in our organisational capabilities to prudently and efficiently address these environmental factors and to deliver the levels of service our customers expect.

SA Power Networks, through the work we have undertaken on our 'Future Operating Model' (Attachment 7.7) has also identified a range of factors which will impact on the delivery of electricity and other services over the next 15 years.

This chapter outlines these operational factors which are a combination of the historical investment in the distribution network, the make-up of the South Australian community and economy, and the growing implications from a rapidly changing consumer and digital world.

There is little doubt that the confluence of customer, technological, market, economic and regulatory changes now underway will drive a period of change in the distribution sector that is unprecedented.

5.1

Distribution services across the State

Of our distribution network, 70% of assets serve the 30% of customers who live in regional areas outside the Adelaide metropolitan area. Only 0.3% of the network services the Adelaide Central Business District (**CBD**). The customer density of the network (averaging only 9 customers per km of network line length) is low compared with other Australian electricity distribution businesses. Average unit costs to connect and service customers are affected significantly by customer density. Despite this customers of the same type (eg residential) pay the same price for network services irrespective of their place of residence.

SA Power Networks operates a relatively long electricity distribution network with much of the network servicing the rural and remote regions of South Australia. The 70% of our assets that serve our regional customers were largely established in the post-war 'electrification' period during the 1950s, 1960s and 1970s. To minimise cost, most regional and rural network lines were built as radial lines with very limited alternative supply paths should there be an interruption. This brings with it many challenges as pinpointing faults on radial lines is time consuming as radial lines may be more than 100 km long and we must often physically inspect the entire line to find a fault.

5.2

Ageing infrastructure

South Australia's distribution network comprises one of the oldest asset fleets in the nation (refer to Section 9.2.1). Spread throughout the State, this ageing network is large and complex, making its efficient maintenance a key challenge for our employees. During this current RCP we have increased our level of inspections of network assets to better understand the condition of these assets that were built around the middle of last century.

Notwithstanding the additional $140 million spent on replacing assets over the last five years compared to the previous five years, these inspections have clearly identified a significant increase in the replacement and maintenance work still to be undertaken if SA Power Networks is to maintain safe and reliable assets and to progressively bring network risk back to acceptable levels consistent with those prior to 2010.

5.3

Community safety expectations

Our consultation programs and surveys confirm that the South Australian community expects SA Power Networks to actively pursue actions to mitigate the potential for power lines to start bushfires, to provide appropriate integrated support for the bushfire strategies of key institutions such as the Country Fire Service and to ensure people's personal safety is not put at risk around network infrastructure.

South Australia faces a high risk of bushfires. The major bushfires in NSW, Victoria and Tasmania in recent years have heightened the community focus on mitigating bushfire risks. The State often experiences hot, dry and windy weather conditions, creating high fire danger in areas that may be tinder-dry and fuel-rich. Some of the highest risk areas include those close to regional centres, in the Adelaide Hills and southern coastal areas.

Although SA Power Networks has one of the nation's most stringent approaches to preparing the network for each year's bushfire season to ensure our assets and operations minimise risks to the community, we recognise the need to adapt to changing climatic conditions and community expectations to ensure our activities are fit for purpose.

In this regard, SA Power Networks has a prescriptive legislative obligation to inspect and clear vegetation from around power lines at regular intervals which cannot exceed three years. The key drivers for managing trees near power lines are bushfire risk mitigation, maintaining reliability of electricity supply and ensuring public safety.

However, balancing the very specific and legislated responsibility for vegetation clearance around power lines with community expectations around aesthetic outcomes is challenging because:

- the specific nature of clearance requirements was framed around safety and reliability requirements, not aesthetics;
- regulator-approved funding of vegetation management is based on a cost-efficient approach where most trees are pruned every three years[8];
- the focus of the community has evolved since the current legislative framework was put in place after the 1983 Ash Wednesday bushfires. At that time there was an understandable and single-minded focus on community safety[9]. Today the community is seeking more holistic and sustainable approaches that both ensure safety and also maintain sustainable trees and environments; and
- removal is sometimes better.

Over the last five to 10 years there has been growing concern regarding tree trimming practices and the clearances required to meet our legislative requirements. As South Australia's electricity distributor, we recognise we have an important role in the economic, social and environmental fabric of our community and acknowledge the importance the community places on the visual amenity of trees in urban and regional settings.

5.4

Sufficient supply to meet customers' energy needs

In determining the appropriate level of capital investment and operational costs, a number of factors that impact on the energy needs of South Australian business and residential customers are taken into account including:

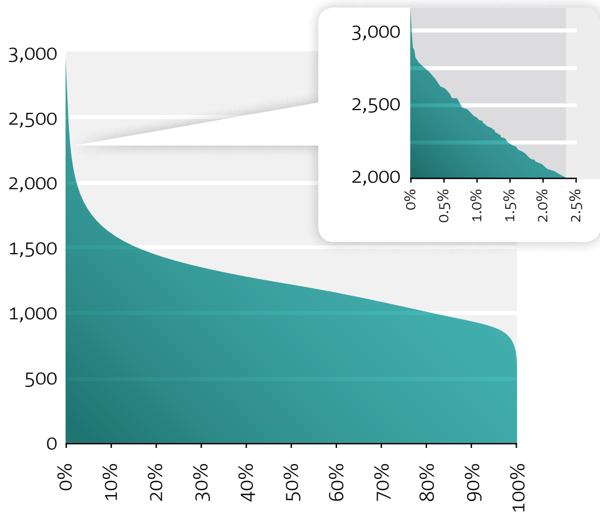
- our climate;
- the prospective growth in our State economy;
- the location of changes in demand across metro and regional locations;
- changes in the number and impact of severe weather events; and
- the changing way energy is produced with increased embedded generation in our network (eg solar PV panels).

5.4.1
Hot and dry climate

South Australia has one of the peakiest electricity demands in the world driven by the extra-ordinary demand for air cooling during our hot summers. More than 90% of South Australian households have air conditioning and the size of those air conditioners continues to grow, placing significant demand on the network. On the few extremely hot days of a South Australian summer, typically around six to nine days each year, air conditioning loads cause South Australia's electricity demand to double relative to average demand levels on mild days.

Air conditioning plays an important role in maintaining reasonable levels of comfort for customers and is critical for the health of many customers. Customers expect SA Power Networks to build sufficient capacity in our network infrastructure to meet these peak demands that occur less than 2% of the year (see Figure 5.1).

Figure 5.1: South Australia's total electricity system demand (MW)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

5.4.2
South Australian economic outlook

Since 2010, international economic conditions have slowly but steadily improved. Global growth continues to pick up with world output growth forecast by the International Monetary Fund to increase from 3.0% in 2013 to 3.6% in 2014 and 3.9% in 2015[10]. China continues to grow at a solid pace with expectations of 7.5% growth in 2014[11]. Considering that one third of Australian exports are now sold to China, our international trade outlook is sound[12].

Nationally, the Australian economy has performed relatively well in the midst of challenging international conditions. There has been the emergence of a two-speed economy with sectors such as mining and construction growing at a pace far greater than manufacturing, retail and tourism (albeit unevenly across the country). However, these weaker sectors are now beginning to strengthen[13]. The Australian dollar has also lowered from recent highs, helping to improve the trade balance[14].

On a state level, although the South Australian economy has experienced difficult times since 2010, the State remains resilient. Recently announced plant closures in the manufacturing industry (eg closure of Holden's local manufacturing operations by 2017) will have a dampening effect on the State economy and employment levels, but

8 Currently we are funded to undertake a mix of one, two and three year pruning cycles in bushfire risk areas and a three year cycle in non-bushfire risk areas.

9 Associated regulations were reviewed in 2008–09 allowing a more risk based approach to be adopted in metropolitan areas. Requirements in bushfire risk areas (**BFRA**) and regional communities remained unchanged.

10 South Australian Department of Treasury and Finance, 2014/15 Budget Statement, 'Chapter 7: South Australian economy', p. 113.

11 Ibid.

12 Deloitte Access Economics, Business Outlook, September 2013, p. i.

13 Deloitte Access Economics, Business Outlook, December 2013, p. ii.

14 Deloitte Access Economics, Business Outlook, March 2014, p. i.

a lower Australian dollar, low interest rates and positive trends in other sectors will help to offset these effects[15].

The State's exports have recently hit a record high and business investment remains at near record levels. Housing construction indicators are also improving, along with recently stronger mining export returns. Additionally, South Australia's Gross State Product is expected to grow by around 2.25% in real terms in 2014/15[16].

Of more direct relevance to SA Power Networks, engineering construction in South Australia continues to be supported by major publicly-funded projects, which are anticipated to sustain investment levels. Also, the housing construction sector has experienced a turnaround since the middle of 2012, with the number of dwellings commencements increasing by 14% from 2012[17].

These trends and latest economic forecasts have been considered and factored into the development of our 2015–20 Proposal, in terms of effects upon energy sales, connections and capacity requirements.

5.4.3
Changes in spatial demand and consumption diversity

While total aggregated demand has moderated in recent years, network 'spatial' demands (ie demands in specific locations) have increased in many areas due to localised economic and demographic changes. SA Power Networks must respond to these spatial demand increases wherever and whenever they occur.

In recent years, demand has decreased at some locations where, for example, manufacturing shut downs may have occurred, while in other parts of the State there has been significant local growth. Parts of the Adelaide Business Area have grown considerably, as have some urban rural centres such as Port Lincoln from growth in aquaculture.

Many regional centres close to the city are also experiencing a rebirth in their economies as retiring baby-boomers seek a 'sea-change' or 'tree-change' and families look for more affordable housing in semi-rural or coastal locations. So, as sizeable portions of the population change their minds about where they want to live, housing developments, suburbs and retirement villages are being developed in diverse locations, driving local network upgrades.

Similarly, the number of single person households is likely to increase due to an ageing population and other demographic trends, while urban planning continues to promote higher density urban living. Demand for such housing and the redevelopment of older housing stock (ie 'infill' development) is forecast to continue in the 2015–20 RCP.

We expect significant workloads for SA Power Networks across South Australia in coming years to serve the changing demographic and lifestyle needs of the community.

SA Power Networks' research has shown that there is a high level of diversity in relation to South Australian peak demands at a spatial level (ie where the combined peak demand of all customers in that location at a given time is less than the peak demand if all customers were consuming their individual peak demand at the same time). This high level of customer diversity has implications for network planning, for pricing (especially for capacity charging) and for any demand management initiatives involving residential customers.

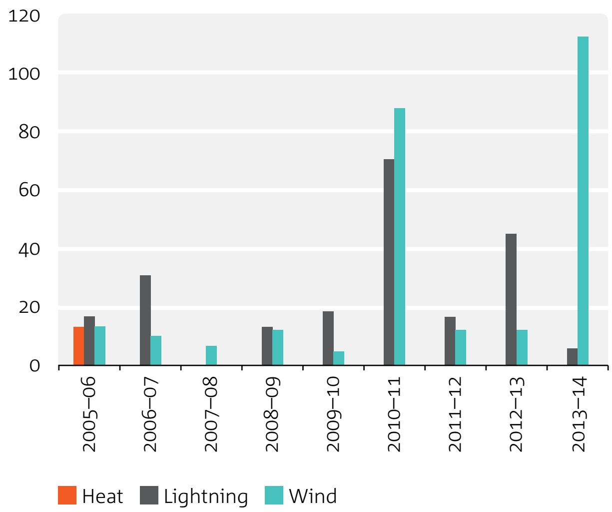
5.4.4
Severe weather events

The number and severity of severe weather events (**SWE**) is increasing. SWEs are the major cause of prolonged interruptions to power supply in South Australia.

Lightning and high winds are the most damaging. Lightning strikes directly damage network equipment, while high winds can blow limbs or whole trees onto power lines. As a result power interruptions can be extended, especially for customers in more remote areas where the network is more sparse and radial lines are longer. In January 2014, South Australia experienced severe heat waves followed in February by one of the most significant storms to hit the network in recent history. This created widespread outages caused by heat-stressed trees falling on poles, power lines and assets. Some 90,000 customers affected were without power for more than twelve hours.

When the impact of a weather event exceeds a specified magnitude on a given day, it is deemed to be Major Event Day (**MED**). These days are typically when storms with lightning and high winds occur. Figure 5.2 shows that the effects of SWEs upon network reliability are increasing.

Figure 5.2: USAIDI contribution, minutes (2005–14 YTD)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

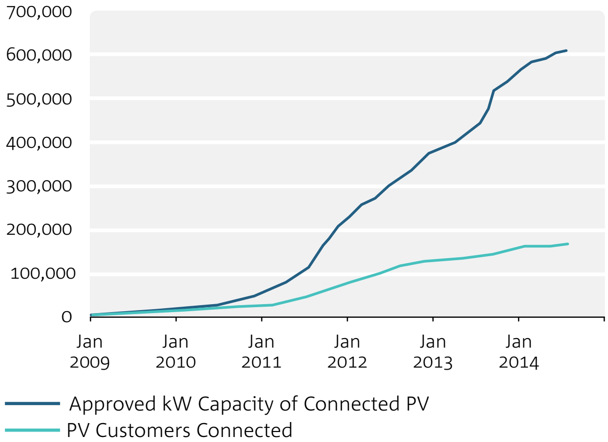
15 Deloitte Access Economics, Business Outlook, March 2014, p. ii and 2014/15 Budget Statement, 'Chapter 7: South Australian economy', p. 113.
16 South Australian Department of Treasury and Finance , 2014/15 Budget Statement, 'Chapter 7: South Australian economy', p. 117.
17 South Australian Department of Treasury and Finance , 2014/15 Budget Statement, 'Chapter 7: South Australian economy', p. 114.

5.4.5
Quality of supply

Quality of supply relates to the physical characteristics of the power customers receive, primarily in terms of voltage. Historically, in the low voltage (**LV**) network quality of supply problems typically have been due to the operation of large and numerous air conditioners during heatwave conditions.

More recently, rapid growth in solar PV installations has accelerated quality of supply issues causing significant local effects in terms of voltage fluctuation, often affecting surrounding customers. South Australia has the highest penetration of domestic rooftop solar PV panels of all NEM regions, with 24% of customers with solar PV installed. (See Figure 5.3)

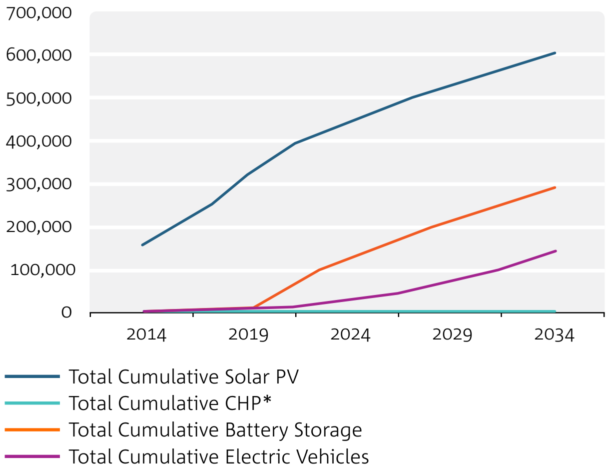
Figure 5.3: No. Solar PV connections to SA Power Networks' distribution network. PV Customers and PV Capacity kW Approved.



SOURCE: SA POWER NETWORKS ANALYSIS 2014

The strong growth in solar PV installations is expected to continue, and beyond that, other new customer equipment such as battery storage and electric vehicles (see Figure 5.4) are likely to exacerbate quality of supply issues over time. SA Power Networks will be increasingly focussed on managing two-way flows across the distribution network and will be required to significantly increase our monitoring and control of the LV network to be able to manage voltage levels within regulated standards.

Figure 5.4: Forecast take-up of distributed energy resources



*CHP: COMBINED HEAT AND POWER
SOURCE: ASSESSMENT OF FUTURE TARIFF SCENARIOS FOR SOUTH AUSTRALIA, ENERGEIA, 2014

5.4.6
Rapid changes in network technology

Technological developments not only provide options for customers, but also create opportunities for improvements to our network operations through new ways to monitor, control, maintain and augment assets that were previously cost prohibitive.

Remote monitoring and control technology is evolving rapidly and quickly expanding the range of cost effective solutions. Installation of more intelligent devices such as transformer monitors, remote-controlled switching devices and advanced meters will help us manage risk and network performance. These technologies also facilitate introduction of flexibility into our network operations that is required to enable the two-way network of the future.

With these changes also comes the requirement to adopt new ways to manage operational devices. They are becoming predominantly electronic devices, which require an increased focus on configuration management, their daily operation and eventual maintenance and replacement programs.

5.5

Significant regulatory developments

There have been a number of significant developments in state and national regulatory frameworks over the last five years which directly impact on SA Power Networks' operations including:

- changes to the economic regulation of network businesses with a greater focus on consumer engagement and the long term interests of customers;
- the commencement on 1 February 2013 of the new National Energy Customer Framework (**NECF**) introducing additional customer protection arrangements;
- the establishment of the solar feed-in scheme and the legislative requirement placed on SA Power Networks to administer that scheme;
- changes to metering arrangements in the lead up to potential competition for these services;
- introduction of revenue control for SA Power Networks for the next RCP;
- continued focus on customer choice and changes to regulatory arrangement to facilitate demand side response by customers;
- the South Australian Government consultation on a draft policy dealing with new and replacement meters in South Australia;
- the confirmation that South Australian reliability standards will continue to be based on historical performance;
- continued community and regulator interest in moving to more cost-reflective pricing and to remove cross-subsidies in network prices;
- changes to the incentive arrangements available to network businesses; and
- extensive data demands from the AER to facilitate its economic and category analysis benchmarking of all network businesses.

SA Power Networks has undertaken the necessary changes to processes and systems where these developments have been introduced such as for NECF and the solar PV feed-in schemes. A number of these developments are yet to be finalised or have future requirements that will impact SA Power Networks' operations over the next five years. Our Proposal includes the necessary investments to perform to these responsibilities.

The most pervasive of these changes will be meeting the AER's demands for actual data for their benchmarking work. The AER consider the incremental burden arising out of Regulatory Information Notice (**RIN**) obligations will be offset by the expected improvements in their ability to assess expenditure proposals, benchmark network businesses and promote efficient expenditure more broadly.

Meeting the initial AER RIN obligations in the first half of 2014 required significant reprioritisation of resources from other parts of the business and significant manual data processes and estimation. The ongoing provision of AER data requirements will come at a significant financial and productivity cost to SA Power Networks as it will require significant data, systems and work practice changes to record and report the requisite actual data.

5.6

Customer expectations — information, access, control and pricing

Changing customer expectations around the range and levels of our services will drive the need to further invest in customer service channels and capabilities. Customers are increasingly able to access high quality information for a whole range of their daily needs with few limitations on location or time due to advances in communications technology. This has raised expectations for accurate, timely information via a wide range of channels including smart phone applications and social networking sites.

Customers are also increasingly accustomed to controlling what information they receive and how they receive it using preferences, portals and dashboards, which they expect to be able to easily configure themselves. Their rising expectations regarding the availability, timeliness, accuracy and relevance of information will need to be met if SA Power Networks is to maintain existing customer satisfaction performance into the future.

As customer needs evolve from relatively simple connection and fault rectification requests to more sophisticated energy management services and support queries, SA Power Networks will need to be prepared to address the changed circumstances. For example, the take-up of distributed energy resources (**DER**) such as solar PV and more generally, demand side participation (**DSP**), has far reaching implications for all parts of our business from the role of our call centre and customer facing systems right through to how we plan, build, operate and maintain the South Australian electricity distribution network.

Customers, regulators and government have also come to recognise that with the many changes to the way energy is produced and used, billing customers solely on the basis of how much energy they consume from the grid is no longer appropriate. Significant focus at a national level has been placed on the introduction of more cost-reflective prices from network businesses.

SA Power Networks introduced an opt-in capacity tariff for residential customers on 1 July 2014 following many years of applying this type of tariff to business customers. A continued transition to more cost-reflective tariffs is considered essential to ensure customers make efficient investment decisions and will reduce the growing level of cross subsidies between customers who do and do not have large air-conditioning systems and/or DER.

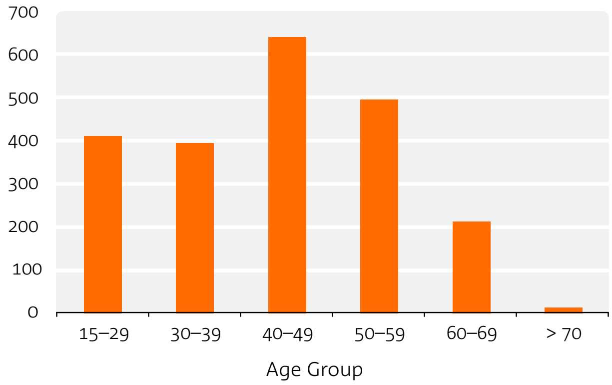
Chapters 6 and 14 provide further details of customer expectations.

5.7

Ageing workforce and new skills

The electricity industry has one of the oldest workforces of all Australian industries, with close to half of workers being aged 45 or over. As at April 2014 the average age of our workforce was 43 years with over 10% of our workers aged 60 and over (see Figure 5.5).

Figure 5.5: No. Employees by Age Group (as at April 14)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

This age profile has been accentuated as many workers delayed retirement following the Global Financial Crisis (**GFC**). Prior to the GFC, the number of our workers in the age range of 60–69 years would be around 155 in a typical year, but by April 2014 this number was 216. Over the next five years about 10% of older workers are expected to retire and will need to be replaced.

Also, a characteristic of our industry is that our work environment is technically specialised and inherently high risk. To build the required skills among our workforce takes considerable time and effort to train and develop new workers and apprentices.

The transitioning and replacement of our ageing workforce, and the recruitment, training and development of new employees are challenges we have been successfully addressing during the current RCP. For example, we have recruited 231 apprentices during the last six years with a retention rate greater than 90%.

We continually assess our forward planning, build our internal workforce development capability and invest in our people through ensuring recruitment and training are appropriate for the roles that the business requires to deliver its plans, now and into the future.

The coming period will be one of renewal for our people. We will invest in the transfer of knowledge and skills to the next generation of employees to maintain deliverability of our work programs. Importantly, we will also maximise the opportunities to bring into the organisation the new skills that will cater for changing customer demands such as those that will accompany the growing impact of digital and new technologies.

6 Our customer engagement

6

SA Power Networks has a reputation for building effective relationships and dialogue with our customers. The voice of our customers is increasingly influencing our many activities, projects and processes, and we routinely monitor closely our customers' satisfaction over a broad range of services and projects.

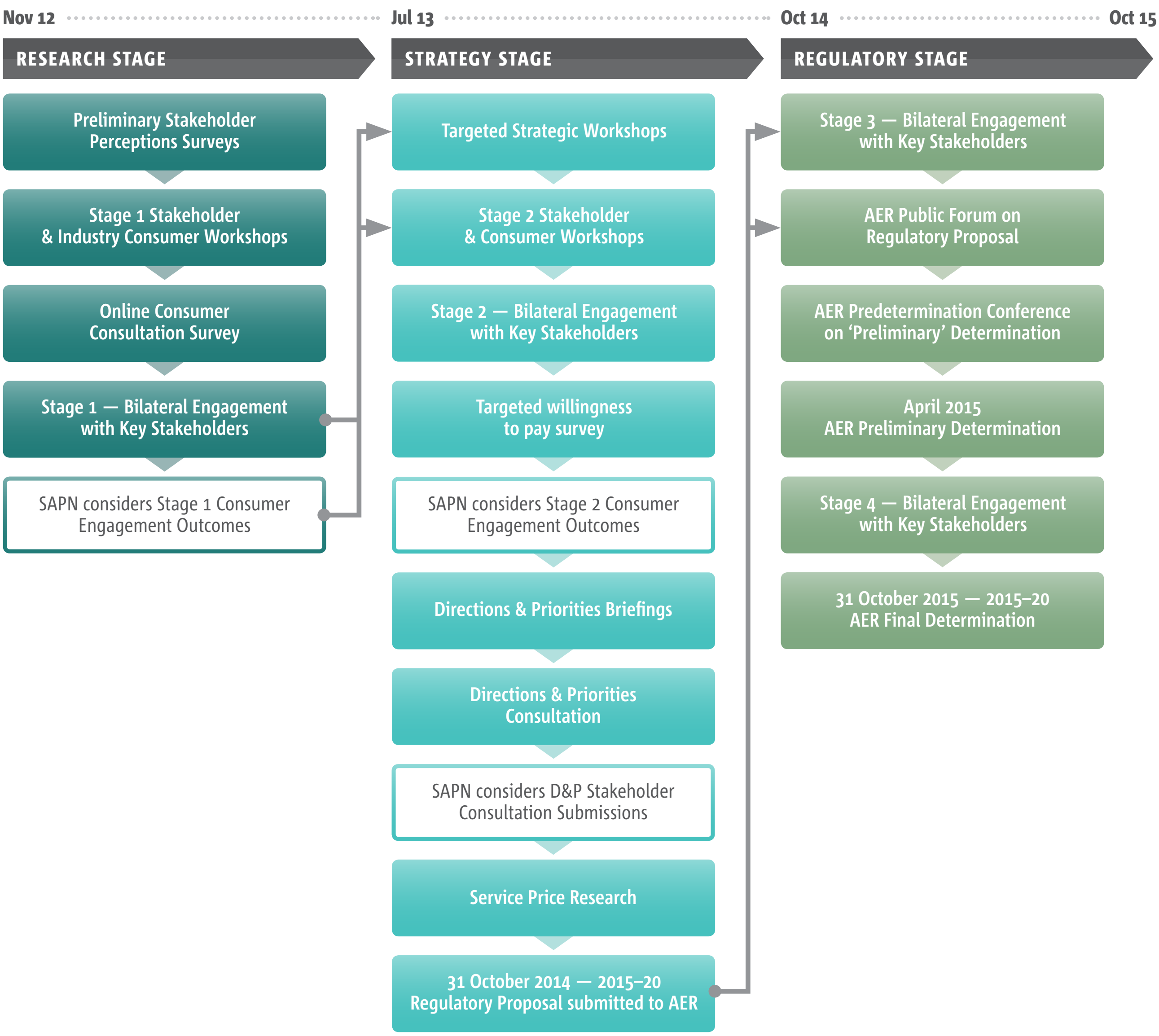
This solid basis, combined with recent stakeholder engagement experience from the UK, was leveraged to develop our Customer Engagement Program the design of which was finalised in 2012, over 12 months before the AER's Consumer Engagement Guideline was finalised. It was important to commence our Customer Engagement Program early enough to enable both the time for effective engagement as well as enough time to consider customer feedback and factor it into our planning for the 2015–20 RCP.

6.1

Overview of TalkingPower program

To guide the development of our 2015–20 Proposal we have implemented a comprehensive Customer Engagement Program, titled 'TalkingPower', to engage with our customers and stakeholders in order to understand their current and future needs, concerns and preferences (Figure 6.1).

Figure 6.1: SA Power Networks' Customer Engagement Program



Our TalkingPower consultation program commenced in the second half of 2012 and is based on key principles. We wanted the program to:

- demonstrate an evidence based process;
- provide relevant information to stakeholders via open and clear communication channels;
- be inclusive and clearly outline what stakeholders can expect from us via our engagement;
- ensure we are positioned to listen early to stakeholders' concerns;
- drive our methodical assessment of those issues and our potential to address them;
- provide prompt and clear feedback to stakeholders on the conclusions reached and actions taken;
- establish good practices that help lead our industry in customer engagement;
- comply with regulatory guidelines; and
- provide a template for ongoing stakeholder engagement outside of reset periods.

As outlined in Figure 6.1 TalkingPower encompassed three distinct stages. The 'Research' stage focused on 'listening'. Providing objective information to customers about the energy industry and network services facilitated identification of our customers' expectations and concerns as inputs into the development of the services and investments required for 2015–20.

An important aspect of this early consultation stage was to ensure customer expectations were discussed with a clear price impact in mind. For example, with the stage one workshops customers were asked to consider their expectations in the context of "network charges that did not increase by more than CPI".

The second stage focused on 'Strategy' and was designed to progress and integrate customer expectations and concerns identified in stage one into our planning for the 2015–20 RCP. The outcomes of this integration in terms of potential investment and services were presented to customers for confirmation during stage two workshops.

This stage also included two collaborative workshops to develop strategies with respect to the undergrounding of power lines and the clearance of vegetation around power lines as well as some willingness to pay research.
A major component of the strategy phase was the release of our 'Directions and Priorities 2015 to 2020' consultation document. This stage will culminate in the submission of this Proposal to the AER on 31 October 2014.

The third 'Regulatory' stage will be focused on the AER's evaluation of our Proposal.

TalkingPower has been independently facilitated by consultants Deloitte and Second Road to ensure independence, and to provide confidence that customer views are robust and fairly represented. These two organisations, and The NTF Group, also provided deep expertise in key matters central to design and implementation of the engagement program at various times.

The AER's Consumer Engagement Guideline provides a high level framework based on best practice principles drawn from the Stakeholder Engagement Standard (**AA1000SES**) and the International Association of Public Participation (**IAP2**) framework. Drawing on AA1000SES and IAP2, the Guideline outlines four best practice principles that should guide all aspects of DNSPs' customer engagement. The principles call for all components of engagement to be:

- clear, accurate, relevant and timely;
- accessible and inclusive;
- transparent; and
- measurable.

TalkingPower was designed based on analogous principles and SA Power Networks has consistently worked to apply them during the implementation phases of our program. Our program can be demonstrated to have promoted effective engagement with a wide range of stakeholders and to have facilitated consideration of customer feedback in development of our business plans and expenditure forecasts for the 2015–20 Regulatory Proposal. Table 6.1 summarises an assessment of our program against the key performance benchmarks discussed above. More detail is available at Attachment 16.6.

Table 6.1: TalkingPower alignment with key performance benchmarks

Performance Benchmarks	Alignment
Stakeholder Engagement Standard (AA1000SES)	●
International Association of Public Participation (IAP2)	●
AER Consumer Engagement Guideline Best practice principles:	
• clear, accurate, relevant and timely;	●
• accessible and inclusive;	●
• transparent; and	●
• measurable.	●
Application of the principles is assessed against all stages of Customer Engagement Program activities ie from initiation, to management of engagement priorities, to delivery, to results acquisition, and finally to evaluation and review.	

SA Power Networks is confident that our comprehensive program meets all requirements for effective customer engagement as outlined in the AER's Consumer Engagement Guideline.

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

6.2

Stage one — Research focus

In early 2012 SA Power Networks embarked on a major review of the way in which major initiatives and strategies align with what customers say they want and value. SA Power Networks engaged ORC International to conduct service value research under the 'Customer Management Model' project.[18] The research included focus groups, in-depth interviews and computer-assisted telephone interviewing (**CATI**) surveys with a random sample of 880 people aged over 18 years during September to November 2012.

This research provided new insights into what lines of service matter to consumers, the relative importance of these lines of service, and how SA Power Networks compares to their expectations. This study is covered in more detail in Section 17.2. The 'service areas' covered by the research included:

- infrastructure;
- bushfire management;
- quality of supply;
- tree pruning;
- meter reading;
- field crews;
- blackouts;
- Power@MyPlace;
- planned outages;
- solar connections;
- streetlights; and
- website.

This work was one of a number of important inputs to determining the scope of our Customer Engagement Program.

Other inputs that were particularly valuable included our regular customer research surveys, our range of regularly updated asset management strategies and plans, recent regulatory reviews such as the Australian Energy Market Commission's (**AEMC**) Power of Choice Review, and our own Future Operating Model work that seeks to identify future energy and network needs, risks, opportunities and directions that are most relevant to SA Power Networks and our customers. The Future Operating Model initiative is discussed further in Chapter 7.

In addition, the design of the program was influenced by the investigation of overseas examples of successful consumer engagement within the utilities sector and included a review of the methods and approaches used in the UK by electricity and gas distribution businesses.

The program's stage one engagement was based around four topic areas that encompassed the most salient issues and factors that will influence our plans going forward. The topics were:

- customer experience;
- community safety and reliability;
- visual amenity; and
- the evolving customer.

18 ORC International, *SA Power Networks Customer Management Model Study — regulatory summary*, February 2013.

6.2.1
Stage one workshops

During the Research stage seven workshops were held in the CBD and in regional South Australia — the Riverland, Mt Gambier, Port Augusta and Port Lincoln — from March to April 2013, with over a hundred electricity customers and stakeholders. Participants included a mix of residents, business, council, welfare and other special interest groups.

The design and conduct of these workshops was independently facilitated by Deloitte. The workshops were designed to include interactive worksheets and activities, question and answer sessions, and information presentations by SA Power Networks' senior management.

The workshops comprised sessions including:

- introduction including SA Power Networks' role, our responsibilities and price context;
- activities to explore customer perceptions of SA Power Networks;
- separate topic sessions on 'Customer experience', 'Community safety and reliability', 'Visual amenity' and 'The evolving customer' incorporating:
  - presentations by SA Power Networks senior managers;
  - question time;
  - brainstorm activities;
  - worksheet activities;
  - discussion/summary of worksheets;
  - closing questions; and
  - future ideas activities.

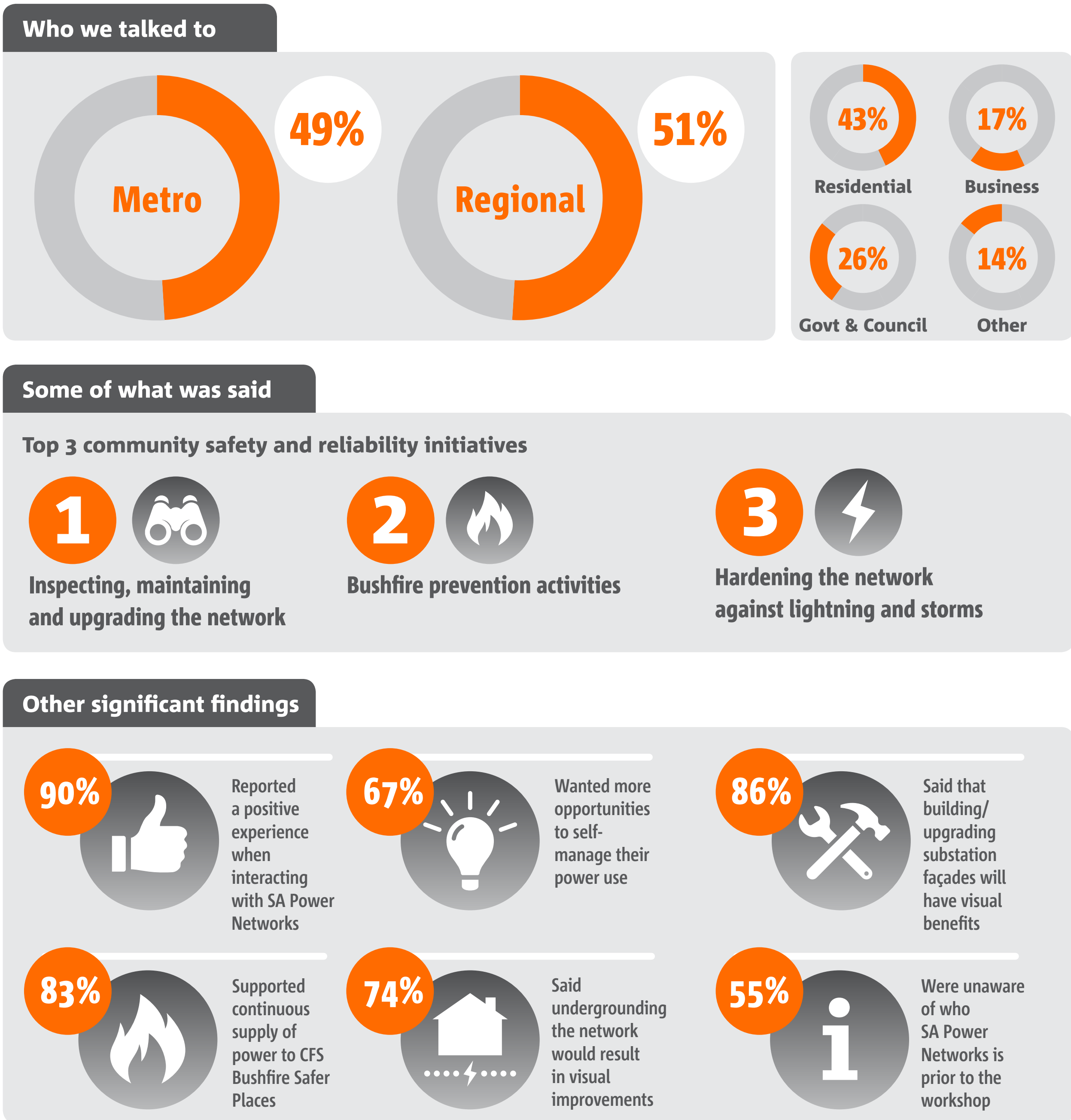
The workshop subject matter in relation to the four topic areas is detailed in Table 6.2.

A snap shot of a portion of the results is provided in Figure 6.2 with the full results detailed in the workshop report prepared by Deloitte which is available on our **TalkingPower.com.au** website and in Attachment 6.3.

Table 6.2: Stage one four topics areas

Stage one workshop topic area	Subject matter covered
Customer experience	• SA Power Networks role and responsibilities; • components of an average bill for business and residential customers; • potential impact on future electricity prices due to planned investments in the next regulatory period; • existing customer self-service tools; • brand awareness; • customer service experience and customer satisfaction; • customer issues and concerns; • ways to improve customer satisfaction; • value of customer service across different channels; • customer experience attributes and how they influence customer satisfaction; • customer preferences for access to services and information; • technology and device usage; and • customer experience expectations for the future.
Community safety and reliability	• what does community safety and reliability mean; • how SA Power Networks manages electricity assets; • key considerations in delivering reliable power including peak load demands, ageing infrastructure, weather events, corrosion, vegetation, bushfires and fluctuating quality of supply from solar; • customer issues and concerns regarding community safety and reliability; • customer satisfaction with current levels of reliability; • ways to improve community safety and reliability; • inspecting, maintaining and upgrading the network; • reinforcing the network; • hardening the network against lightning and storms; • ageing infrastructure and its relationship to asset inspection and replacement programs; • why and how SA Power Networks clears vegetation; • issues and concerns surrounding vegetation trimming; • exploring ways to address customer concerns including more frequent tree trimming, planting the right vegetation in the community and undergrounding wires or tree removal/replacement; • customer education requirements surrounding vegetation trimming; • how SA Power Networks minimises bushfire risks; • ensuring CFS bushfire safer precincts have supply during extreme weather conditions; • more frequent inspections and maintenance; and • building power lines less prone to fire starts.
Visual amenity	• the importance of visual amenity; • how can SA Power Networks improve the visual impact of the network; • undergrounding of power lines and examples; • upgrading substations to fit their setting; • customer issues and concerns regarding 'fit-for-setting' substations; • customer criteria for prioritising enhancements to substations to be fit-for-setting; • suitable locations for 'fit-for setting' substations; • undergrounding for visual amenity; and • customer criteria for prioritising undergrounding.
The evolving customer	• what could happen in the future; • customer awareness of the impact of new technologies on the electricity network; • what can be done to meet evolving customer needs including upgrades to support a two-way network, exploring cost-reflective pricing and the introduction of smart meters and energy management systems; • customer awareness of smart meters and their benefits; • customer knowledge and value of cost-reflective tariffs; • customer understanding and their education needs regarding new tariffs and metering systems; and • future ideas including what kinds of information, services and products customers desire.

Figure 6.2: Deloitte stage one workshop results snapshot



6.2.2
Stage one online survey

Over three weeks from May through to June 2013 an online survey was conducted. The survey design was facilitated by Deloitte and was independently tested prior to release. The survey structure mirrored the themes of the stage one workshops and used a design refined with the benefit of workshop insights, allowing a deeper exploration of customer information on:

- customer perceptions on services they receive from SA Power Networks;
- customer segmentation and demographics;
- customer perceptions regarding customer service and reliability;
- customer technology adoption and usage; and
- customer solar usage.

For SA Power Networks, the Essential Services Commission of South Australia (**ESCoSA**) retains responsibility for setting service levels via 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 designed by ESCoSA. This process was facilitated independently of both organisations by Deloitte. ESCoSA 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.

The survey was widely publicised through State and local papers, online media, metropolitan and regional radio, as well as social media channels as described in Table 6.3.

Table 6.3: Stage one online survey promotion — summary of advertising audience

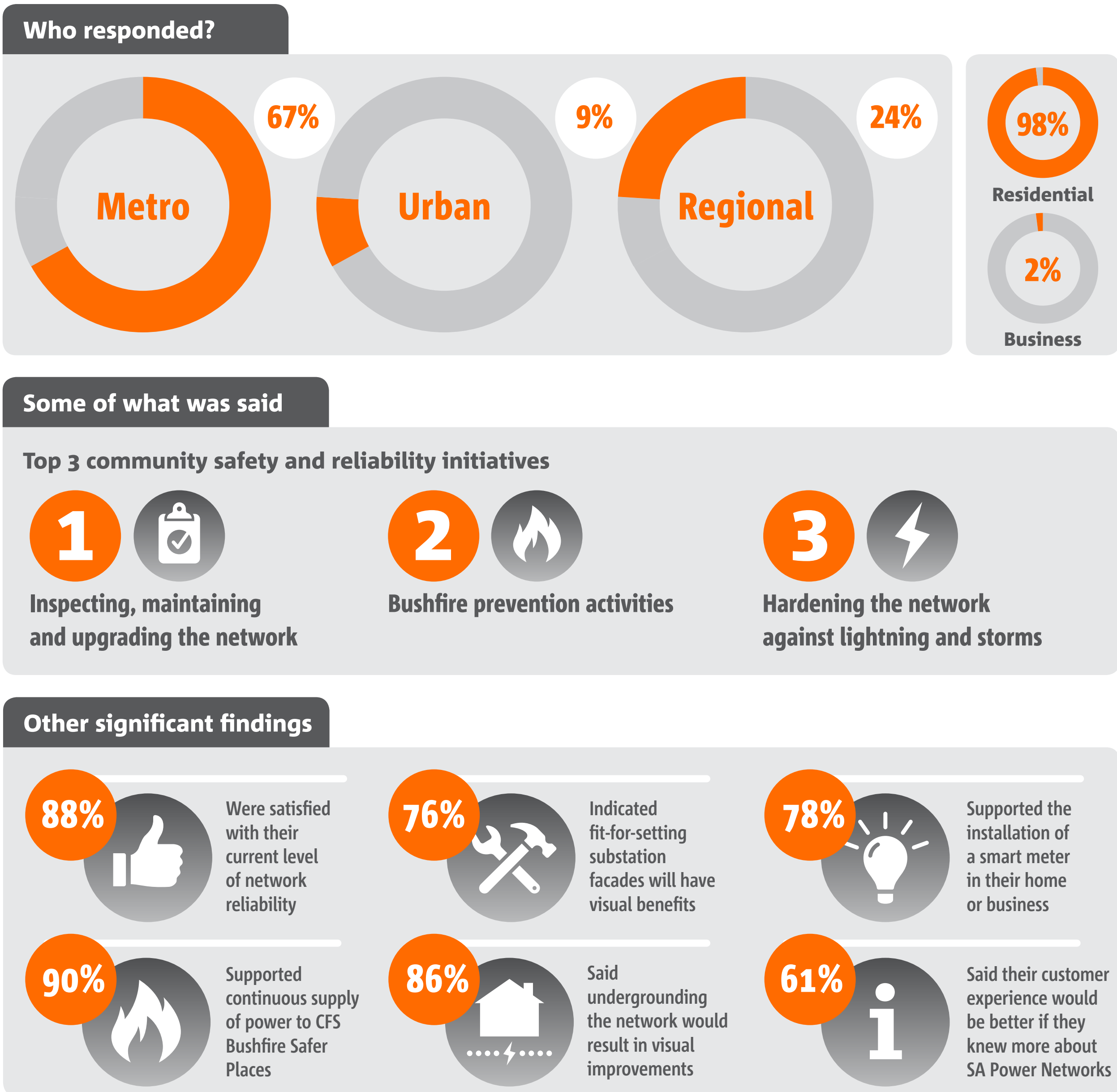
	Audience	Reach
Press promotion	448,659	891,813
Radio promotion	83,220	6,840,000
Online promotion	23,019	5,937,451
Social Media	18,911	1,306,039
TalkingPower website	632* (unique visitors)	1,503*
Database marketing	114*	124*

*Does not include SA Power Networks staff.

In all 2883 responses were received from South Australian customers (aged 17 to 65 plus) and is representative of the population. The results provide a clear indication of our customer preferences.

A snap shot of the results is provided in Figure 6.3 with the full results detailed in the survey report prepared by Deloitte which is available on our **TalkingPower.com.au** website and in Attachment 6.5.

Figure 6.3: Deloitte Stage one online consumer survey results snapshot



6.2.3
Summary of customer preferences from stage one

The concerns and preferences of South Australian customers were clear and were distilled into 13 key insights by Deloitte (see Figure 6.4).

Figure 6.4: What we have learnt from our stakeholders and customers[19]

13 key 'insights' based on the views of South Australian electricity customers were drawn from the research stage of the TalkingPower Customer Engagement Program. The program confirmed customers want us to:	
1	**Educate customers about the South Australian electricity industry and SA Power Networks' role.** Customers indicate they would like more information and consultation about SA Power Networks' role in delivering electricity, the role of retailers and the electricity industry in South Australia.
2	**Maximise opportunities to improve service experience.** Customers rate their overall customer experience as positive or neutral while urging SA Power Networks to improve service interactions wherever possible.
3	**Develop multi-channel communication strategies.** Customers want to interact with SA Power Networks using multiple channels (voice, telephone, text, email and social media) for a variety of different actions.
4	**Continue managing assets and investment to drive reliability, manage risk and support economic growth.** Customers rank any asset management initiatives with a direct impact on reliability and/or preventing potential safety hazards as most important. Priority areas included assets located in high bushfire risk areas and near roads in residential areas. Business customers also identified areas that would support economic growth.
5	**Design vegetation management programs (tree pruning) to consider their visual impact.** Customers support vegetation management activities that improved the visual aesthetics and would benefit the wider community.
6	**Prioritise preventative maintenance to reduce risk.** All preventative initiatives should consider potential safety hazards and be completed as a priority when they can help to reduce risks.
7	**Ensure CFS Bushfire Safer Places have continuous power.** Investment in bushfire management initiatives would help to ensure that essential services can be maintained in specific safer places under critical conditions.
8	**Maximise opportunities to improve the visual appearance of assets.** Almost everybody supports initiatives to underground the network and improve the appearance of substation facades. This is a customer priority in areas where the visual appearance of the network has the largest effect on the community.
9	**Consider improvements in public safety and reliability in asset planning.** High bushfire risk areas and areas where additional safety and reliability benefits could be realised are customer priority areas for undergrounding the network.
10	**Consider installing advanced meters.** Customers support the adoption of advanced meters to give them greater control over their electricity usage.
11	**Continue upgrades to support a two-way network.** Almost universally, customers favour upgrades to enable a two-way network to support the increasing uptake of new technologies.
12	**Develop cost-reflective pricing tariffs.** Customers are in favour of developing and phasing-in socially equitable cost-reflective pricing strategies.
13	**Educate customers about new technology and industry change to help increase their satisfaction.** Customers say they need education on new technologies and changes to the industry.

19 Deloitte, Stage 2 Stakeholder and Consumer Workshop report

6.3

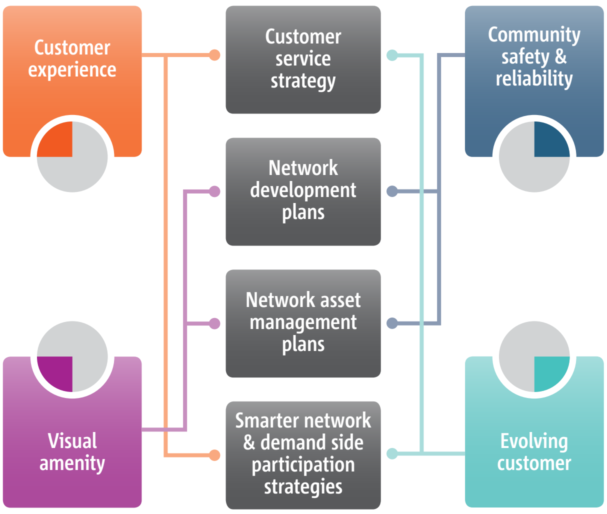
Stage two — strategy focus

6.3.1
Integration into business

The first step in stage two was designed to enable customers' input derived from stage one consultation to be incorporated into business planning. Effective communication of stage one insights to relevant staff allowed for consideration of the types and levels of services that customers expect to be provided during 2015–20 and to identify the potential investment required to deliver on these customer expectations.

In July 2013, a workshop was held involving 30 SA Power Networks' business leaders. At this workshop Deloitte presented their findings from the customer workshops and surveys to our business leaders who then workshopped a range of services and opportunities that might deliver on customer expectations, noting that many of the customer insights were directly relevant to SA Power Networks' core business activities. These opportunities were then further considered and analysed by the responsible business areas to develop plans and refine approaches. Figure 6.5 illustrates how the customer insights are related to the various business strategy areas and plans developed by SA Power Networks.

Figure 6.5: Interrelationships between customer insights and SA Power Networks' strategies and plans



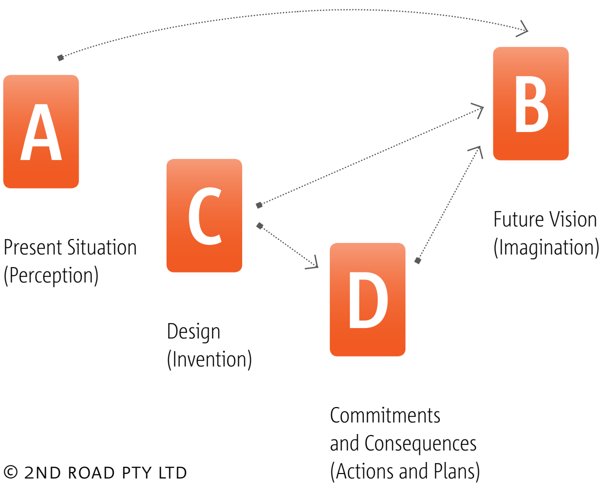
Stage one insights were also leveraged in separate customer research undertaken to help develop the Customer Service Strategy 2014–2020. In August through to September 2013 customer-focused workshops with 130 customers was conducted for SA Power Networks by Deloitte. These workshops delved even further into customer segmentation, service needs and expectations, channel preferences, suggestions for improved customer service, website and self-service tools reviews, as well as feedback and ideas for future products and services.

6.3.2
Stage two targeted strategic workshops

Arising from the business' consideration of the customer insights and the potential responses, two key areas — undergrounding power lines and managing vegetation clearance — were selected for further exploration with customers and subject matter experts. As there were a wide range of possibilities we considered that these two areas would benefit from further focus on potential approaches to delivering on customer expectations. We adopted advanced stakeholder engagement techniques including 'design-thinking' methods to explore the topics further in two separate targeted strategic workshops held in early October 2013.

Independent consultants Second Road were engaged to assist with the development of an approach which would extend the engagement process into one where customers and their representatives were involved in a collaborative process to determine feasible strategies to address the issues. Second Road have pioneered, and are expert practitioners in, the art of 'strategic conversation' — an engaging way of cohering groups around vision and purpose to progress to developing a clear and actionable set of initiatives. Figure 6.6 illustrates the ACDB methodology which forms the framework for the strategic conversation approach.

Figure 6.6: Second Road strategic conversation process



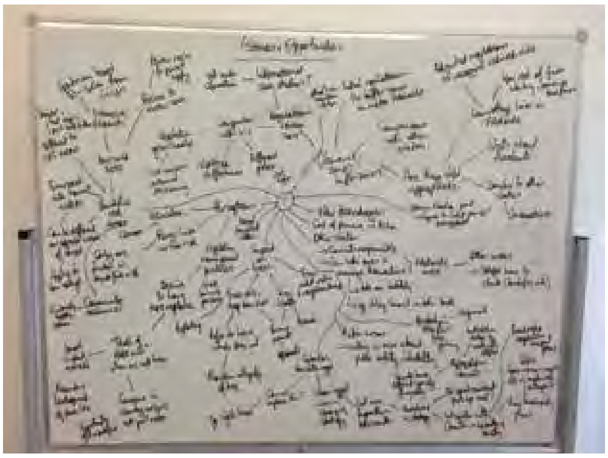
Second Road consultants facilitated the two targeted strategic workshops and participants included customers from stage one workshops, external parties with relevant expertise on the topic as well as key SA Power Networks personnel with responsibility for the relevant business area. Participants were provided with objective information about the respective topic including regulatory and safety obligations, the cost of undergrounding power lines and the annual cost of vegetation clearance.

Workshop participants explored perceptions of the present situation, evaluated possible alternatives with the required commitments (including the consequences) of implementation in order to develop a future vision. A mind-map of the options explored in the vegetation management workshop is shown in Figure 6.7.

Customers and subject matter experts concluded that SA Power Networks should develop undergrounding and vegetation management strategies that place more emphasis on the long term whilst balancing the benefits with the costs. The initiatives proposed by the workgroups include:

- further consultation and partnering with communities and groups;
- preserve community safety as a priority;
- minimise vegetation management (tree trimming) over the longer term;
- habitat creation programs in priority areas, including the removal and replacement of trees;
- more advanced tree trimming practices;
- a differentiated range of tree trimming approaches to suit different regions and/or environments;
- undergrounding high risk power lines and assets in high bushfire risk zones;
- undergrounding high risk power lines and assets for improved road safety; and
- where practical place some priority on undergrounding power lines when replacing assets.

Figure 6.7: Targeted strategic workshop participant exploration of 'issues and opportunities' for vegetation management solutions



As a result of the customer-designed principles and proposals developed in the workshops, two internal SA Power Networks working groups were established to further progress each approach. These results were presented to participants at a subsequent briefing in March 2014 to close the loop and ensure the customer and stakeholder group could see how their input had affected our decision making in these areas. Participants were also presented with the outcomes of resultant Willingness to Pay research which is discussed further in Section 6.3.4.

6.3.3
Stage two workshops

Eight stage 2 workshops were held around the State in October and November 2013 at the same locations as those in stage one. The need for an additional workshop on Kangaroo Island was also determined during bilateral engagement discussions. Participants from stage one workshops were invited to attend. The workshops were facilitated by Deloitte to:

- validate the stage one research findings;
- present and validate the customer-designed vegetation management and undergrounding proposals;
- test customer sentiment on SA Power Networks' views on ESCoSA's draft SSF (including proposed changes to the Guaranteed Service Level (**GSL**) scheme);
- outline SA Power Networks' broad plans; and
- obtain customers' views on how well we had captured customer insights in our broad business plans.

During the workshops Deloitte presented the 13 consolidated consumer insights from stage one to participants and facilitated group discussions to understand how accurately the insights reflected their views as South Australian electricity consumers. SA Power Networks shared details of future business plans, and how these plans evolved in response to consumer insights. During the stage two workshops, participants were made aware that as at October-November 2013, it was anticipated that network prices in the 2015–20 RCP would be limited to no more than a CPI increase.

Workshop feedback indicated that participants valued this process and viewed the stage two workshops as an important aspect of the program. Participants also confirmed these workshops indicated that SA Power Networks is listening to, and acting upon, the insights gathered from customers.

The stage two stakeholder and consumer workshop report prepared by Deloitte is available on our **TalkingPower.com.au** website and in Attachment 6.7.

6.3.4
Willingness to Pay survey

As the customer initiated principles and proposals for undergrounding and vegetation management do translate to a range of investment levels, SA Power Networks considered it prudent to test Willingness to Pay using discrete choice modelling techniques. This Willingness to Pay research was independently carried out by The NTF Group during January and February 2014 and involved responses from 895 customers aged 18 to 65 plus. We also undertook some qualitative research on these matters with hardship customers in April 2014.

The service improvements tested in the Willingness to Pay research comprised combinations of vegetation management activities and undergrounding power lines in high bushfire risk areas (**HBFRA**), bushfire risk areas (**BFRA**) and non-bushfire risk areas (**NBFRA**).

Community consultation confirmed majority support and Willingness to Pay for the following service enhancements:

- implementing a program for 2.5% removal and replacement of vegetation in NBFRA, HBFRA and BFRA;
- move from a 3 year to a 2 year trimming cycle for vegetation near power lines in NBFRA;
- undergrounding up to 135kms of power lines in HBFRA; and
- undergrounding power lines around 20 traffic black spots in NBFRA.

The research results and the revised strategies were subsequently fed back to the March 2014 briefing discussed above. The research summary prepared by The NTF Group is available on our **TalkingPower.com.au** website, in Attachment 6.8, and further discussed in Chapters 11 and 15.

6.4

Key stakeholder bilateral engagement

At various times during our Customer Engagement Program we engaged directly with representative stakeholders on a bilateral basis to create the opportunity to address their specific issues or concerns and to keep key stakeholders informed. These two-way discussions included individual stakeholder concerns, cost of living pressures, progress and findings from our Customer Engagement Program, along with our 'Directions and Priorities 2015 to 2020' consultation.

Over 100 key stakeholder representatives and stakeholder groups were identified in the bilateral component of our program. Target audience groups fell into five broad categories:

- **Business** — 99,332 small, medium and large business customers;
- **Other interest groups** — vulnerable customer groups, special interest groups and the media;
- **Government and Regulatory** — Ministers, State Government Departments, local Government and Councils, the AER, ESCoSA and the OTR;
- **Market participants** — retailers, transmission and generation; and
- **Corporate** — personnel, investors and SA Power Networks' Customer Consultative Panel.

To build on the outcomes and strategies identified in the TSW on vegetation management, we commenced a focussed engagement program with local Councils and the Local Government Association (**LGA**) of South Australia on the specific issue of vegetation management, to help align Local and State Government stakeholders and community preferences. This program includes:

- an annual Local Government forum on vegetation management;
- the development of two reference groups — a LGA/Council Working Group and an Arborist Reference Group, to progress strategic initiatives and develop a protocol for vegetation management near power lines;
- joint tree removal trials; and
- consultation with the LGA on the development of a discussion paper titled "SA Power Networks' long-term plan for managing trees near power lines".

SA Power Networks' Customer Consultative Panel (**SAPN CCP**) was established in 2007 to facilitate structured discussion on our performance, plans and opportunities for improvement. The SAPN CCP meets quarterly and has played a key role in the review of our Customer Engagement Program and development of our Regulatory Proposal.

The Energy Consumers' Council (**ECC**) provides high level policy advice to the South Australian Energy Minister on energy policy issues, including pricing and the reliability of supplies and services in the South Australian energy sector. In our engagements with the ECC, their feedback has focused on electricity prices, corporate profits, support for energy management and emerging technology.

The AER's Consumer Challenge Panel sub-panel established for SA Power Networks' regulatory determination (**CCP2**) is chartered to provide an independent consumer perspective to the AER to help ensure that decisions on network services and costs incorporate the long-term interests of consumers. Interactions with the CCP2 have been focused on:

- regulated network revenue, opex and capex requirements, pass throughs, peak demand and demand growth, annual usage, consumer numbers;
- customer tariffs and residential network prices increases;
- network age profile and replacement costs;
- consumer engagement research methodologies including our approach to assessing Willingness to Pay, in particular around reliability;
- ESCoSA's reliability standards; and
- South Australian customers' capacity to understand our regulatory proposals to the AER along with our ability to engage with different customer segments.

6.5

Directions and Priorities 2015 to 2020 consultation

The 2015–20 RCP will see the most significant and transformative change in the distribution sector since the establishment of the NEM. In this environment, an intense focus on changes in the key dimensions of our operating environment is essential if we are to identify the appropriate objectives, strategies and work programs that will enable sustainable performance by SA Power Networks, in the long term interests of customers and other stakeholders.

SA Power Networks' assessment is that the complexity and scale of the changes ahead called for a new level of transparency and accessibility in terms of public consultation on our directions and priorities. Our 'Directions and Priorities 2015 to 2020' consultation document was the result of this assessment, and represented a new benchmark in our sector with regard to services for the future, and importantly regarding the prices customers can expect to pay for them.

The consultation document itself is innovative and structured according to the 'service areas' that represent high-level services provided by SA Power Networks to customers and the community.

These service areas are:

- keeping the power on for South Australians;
- responding to severe weather events;
- safety for the community;
- growing the network in line with South Australia's needs;
- ensuring power supply meets voltage and quality standards;
- serving customers now and in the future;
- fitting in with our streets and communities; and
- capabilities to meet our challenges.

The 'Directions and Priorities 2015 to 2020' consultation document (see Attachment 6.10) was designed to be easy to read by customers and contain sufficient detail to enable customers to understand the proposed investments and the pricing impact of the overall draft proposals, in order to facilitate valuable and actionable feedback.

The 'Directions and Priorities 2015 to 2020' public consultation was initiated on 13 May 2014 and included briefings in Adelaide, the Riverland, Mt Gambier, Port Augusta and Port Lincoln. The consultation opportunity was widely promoted, as described in Table 6.4, and submissions were open to all customers.

Table 6.4: Directions and Priorities 2015 to 2020 consultation process promotion — summary of advertising audience

	Audience	Reach
Press	194,558	1,751,022
Radio	20,263	1,093,000
Social Media	43,246	-
TalkingPower website	1,594* (unique visitors)	1,612*
Database marketing	1,501*	-
Soft copy downloads	378	-
Hard copy distribution	550*	-

*Does not include SA Power Networks staff.

Figure 6.8 replicates the summary of proposed expenditures from pages 44–45 in the 'Directions and Priorities 2015 to 2020' consultation document.

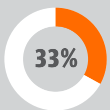
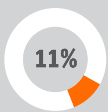
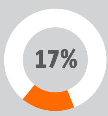
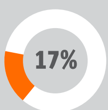
Figure 6.8: 'Directions and Priorities 2015 to 2020' — summary of proposed expenditure

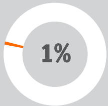
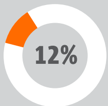
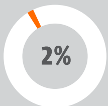
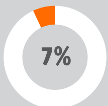
Proposed expenditure for 2015 to 2020 and indicative price impacts

Delivering a reliable electricity supply at the lowest possible price, while also delivering the range of services valued by our customers, remains a fundamental objective for SA Power Networks in the 2015 to 2020 period.

Key points

- This consultation paper has outlined our key services for our customers and community, the changes in our environment, our objectives and our proposed investments for the 2015 to 2020 period.
- Across all these directions and priorities, the concerns and preferences of customers have been given paramount importance.
- To provide customers with insight into the relative investments associated with these proposals, this section indicates the approximate split of total investments by directions and priorities section.
- We believe these proposed investments represent an appropriate balance of initiatives addressing both short term and long term concerns, and an appropriate balance of service and price.
- Our modelling shows these investments and outcomes are achievable with a reduction in network charges of around 4% in 2015 and no more than a CPI increase in the following years, on average.

Item	Key points
Keeping the power on for South Australians 	**33% of Total Expenditure on 'Keeping the power on for South Australians'** • maintain the current underlying network reliability performance; • invest in replacing and refurbishing aged assets to maintain the distribution network reliability performance; • continue our Condition Based Risk Management (CBRM) asset inspection and data collection program; • invest in integrated IT and communications systems that support the application of modern CBRM approaches; • continue to work with stakeholders, particularly in relation to vegetation management; • invest in depot resources to ensure timely restoration of supply across South Australia; and • install a new Kangaroo Island submarine cable to secure supply to the island.
Responding to severe weather events 	**11% of Total Expenditure on 'Responding to severe weather events'** • more frequent inspection of the most vulnerable parts of the network and undertake preventative maintenance and replacements; • continue investing in hardening sections of the network most vulnerable to lightning and storms; • address specific radial line constraints where it is cost effective to do so; • design and build new assets for the network that are sufficiently robust for the changing operating environment and more onerous operating conditions; and • continue to invest in facilities, staff, fleet and technology to ensure timely restoration of supply across South Australia.
Safety for the community 	**17% of Total Expenditure on ensuring 'Safety for the community'** • progressively reinforce power supply to CFS Bushfire Safer Places; • increase the frequency of inspections and maintenance in Bushfire Risk Areas to further reduce risk; • invest in a tree removal and replacement program; • build power lines less prone to starting fires in high risk areas; • implement key findings from the Victorian Bushfire Royal Commission Final Report where they are appropriate for South Australian conditions; • continue managing vegetation clearance to ensure compliance in Bushfire Risk Areas while working towards a more sustainable and long-term approach; • increased community consultation on vegetation management approaches; • targeted program of undergrounding to reduce the potential for vehicle collisions with stobie poles; • invest in community education to improve safety awareness around power lines; and • invest in strategies to address and prioritise the risks posed by older assets to the community.
Growing the network in line with South Australia's needs 	**17% of Total Expenditure on activities that will support 'Growing the network in line with South Australia's needs'** • invest efficiently by aligning our plans with industry and demographic needs; • maintain close connections with stakeholders to ensure that the implications for planned infrastructure developments are understood; • connect customers efficiently in line with our regulatory obligations; and • reinforce our network to manage the impact of urban infill.

Item	Key points
Ensuring power supply meets voltage and quality standards 	**1% of Total Expenditure on activities that will 'Ensure power supply meets voltage and quality standards'** • proactively and selectively monitor the LV network to more accurately plan low voltage capacity upgrades in a world of rapidly evolving technology; • improve our knowledge and support customer take-up of Distibuted Energy Resources (DER) such as micro-generation, energy storage and electric vehicles; • address quality of supply issues in the worst performing areas of the network; and • enable a two-way network through strategic monitoring and prepare the network to support additional embedded generation and customer equipment.
Serving customers, now and in the future 	**12% of Total Expenditure on 'Serving customers, now and in the future'** • further develop self-service options for our customers; • develop multi-channel communication tools to interact with our customers; • undertake initiatives to enable an efficient and fair transition to a two-way network to facilitate continued take-up of solar PV systems that feed excess energy into the network; • strengthen data collection and information flows from our field personnel to customers to provide accurate and timely information on service and restoration activities; • implement systems to allow a single view of the customer and enable the service to be tailored and to be responsive to their needs; • Implement our customer service technology plan; • be a of trusted source of information and advice for customers' current and future electricity needs; • introduce cost reflective tariffs to promote efficient customer investment in DER; and • rollout advanced meters and cost reflective tariffs to give customers more control over energy use and peak demand.
Fitting in with our streets and communities 	**2% of Total Expenditure that will enable us to meet our stakeholders and customers preferences for our infrastructure to 'Fit in with streets and communities'** • implement an enhanced program of vegetation management to improve tree-trimming outcomes in the long-term; • underground power lines in a prioritised program of undergrounding in high bushfire risk areas, and for improved road safety; and • building fit-for-setting substation facades where cost effective.
Capabilities to meet our challenges 	**7% of Total Expenditure that will enable SA Power Networks to meet the challenges of the next regulatory period** • invest in continuous improvement of our governance programs; • maintain advanced stakeholder engagement and long term planning to ensure we keep abreast of expectations, requirements and technological and market developments; • drive our systems and culture to support great customer service and outcomes; • refining our integrated resource planning capabilities to deliver on our work programs; • continue investing in modern and safe standards of property, technology and systems, equipment and vehicles to deliver the work programs; and • invest in the IT systems and capabilities we need to deal with a step change in operational complexity associated with advanced metering, billing requirements, new regulatory reporting and service requirements, customer service expectations, workforce mobility, and advanced asset management capabilities.

Distribution revenue requirements and prices

Allowable distribution revenues are determined by the AER using a 'building block' approach. This entails a review of each separate cost element and then adding them up to arrive at the allowable revenue for the five years of the regulatory control period. The 'building block' components are:

- **Return on Assets,** covering Cost of Debt and Equity calculated by applying Rate of Return to the Depreciated Regulated Asset Base (RAB)
- **Return of Assets** (Depreciation of RAB)
- **Operating Expenditure**
- **Tax Allowance**
- **Incentive Scheme Adjustments** (if any, from previous regulatory control periods)

The revenue requirements derived from the building blocks are distributed across the individual years of the regulatory control period. These revenues ($) are divided by a forecast of electricity sales (MWh) to calculate the average price outcomes ($ per MWh).

Distribution price outlook 2015 to 2020

Key factors in developing our price outlook include:

- Total expenditure comprising capital expenditure of $2.9 billion and operating expenditure $1.5 billion (in 2015$) associated with our proposed directions and priorities;
- A depreciated Regulated Asset Base of $5.5 billion in 2020 (in 2015$);
- Depreciation of assets of $0.9 billion (in 2015$);
- Rate of Return of 8.08% based on the AER Guideline for Cost of Debt of 6.8% and a Cost of Equity of 10.0%; and
- A tax allowance based on gamma of 0.25 as determined by the Australian Competition Tribunal.

The above expenditure includes capital expenditure of $264 million and operating expenditure of $36 million for customer requested investments to deliver reliable power to some bushfire safer places, to improve the way trees are managed around power lines and to underground some power lines to improve road safety.

Our modelling of the indicative price impact on customers shows that the directions and priorities described in this document would see a reduction in network charges of around 4% in 2015 and no more than a CPI increase in the following years, on average. Assuming other things are equal, this means that between 2015 and 2020 the average residential electricity bill would increase by less than 1% per annum on average.

We received nine written submissions in response to the 'Directions and Priorities 2015 to 2020' consultation process. They came from a small cross-section of the community including electricity consumers, businesses, Government, Council, welfare and consumer groups. A number of themes were evident amongst the submissions including:

- sensitivity to rises in electricity costs from businesses;
- general concern about residential cost of living pressures;
- support for maintenance of the South Australian distribution network, in terms of safety and delivering reliability performance;
- support for efficient business practices on the part of SA Power Networks, in the interests of containing prices;
- endorsement of efforts to contain or reduce network peak demands;
- support for the introduction of smart meters;
- support for ongoing connection of distributed energy generation (mainly solar PV);
- support for ongoing moves toward cost-reflective tariffs;
- support for a balanced approach to enhanced vegetation management practices;
- support for addressing road traffic hazards posed by electricity infrastructure; and
- support for a new Kangaroo Island undersea cable.

'Directions and Priorities 2015 to 2020' stimulated discussion about the way forward for the distribution network and our services for South Australian customers. All feedback received from our submissions has been considered in developing our Regulatory Proposal and comments (both positive and negative) from these submissions are discussed in the relevant detailed chapters 9 to 16. In these chapters we make clear where specific customer feedback has led to modifying or maintaining our approach to key investment areas for the 2015–20 RCP.

6.6

Customer feedback on our TalkingPower engagement program

SA Power Networks is confident that the TalkingPower program has been highly effective and worthwhile. The level of participation, commentary and ideas flowing from customers throughout the program has been outstanding. It has enabled us to enhance our Regulatory Proposal, gives us the confidence that the investments being put forward are consistent with our customers' preferences and expectations and has been very much appreciated by us.

Stage One Workshop

"Informative and very well presented. Good to see company CEO of a major corporate body willing to interact with general public and take advice."
Resident, Metro

Participants in workshops, surveys, briefings and our 'Directions and Priorities 2015 to 2020' consultation were given the opportunity to provide feedback on their engagement experience, the engagement process, and the content and conduct of the workshops. The vast majority of this feedback has been overwhelmingly positive and the critical comments will assist in further enhancing our engagement programs over the coming years. Pleasingly, participants requested ongoing engagement on electricity industry issues affecting them and their communities.

Feedback from participants shows:

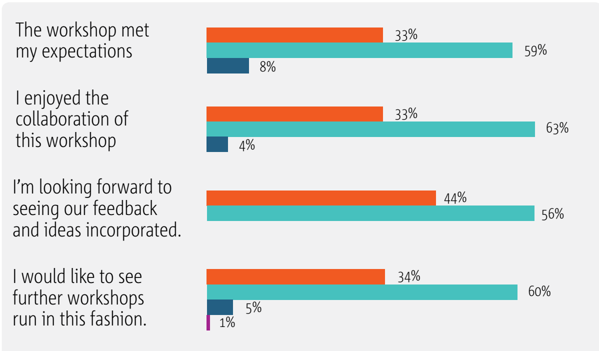
- 92% of Stage one workshop participants agreed or strongly agreed the workshop met their expectations;
- 94% of Stage one workshops participants would like to see further workshops run in the same fashion;
- 75% of Stage one online survey participants indicated willingness to participate in future surveys; and
- 98% of Stage two workshop participants indicated they would like to be involved in future workshops.

Stage 2 Workshop

"Good to see SA Power Networks has listened to previous sessions and are doing things and making changes."
Resident, Metro

Feedback from participants of the TalkingPower workshops, briefings and surveys indicates that participants value the level of engagement and the program (refer to Figures 6.9 and 6.10).

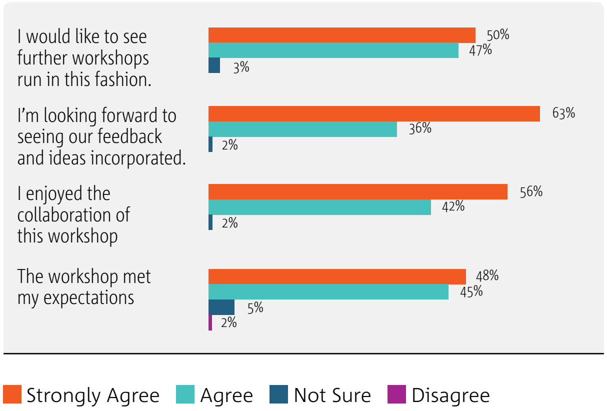
Figure 6.9: Participant feedback on stage one workshops
11 April to 19 April 2013



Strongly Agree Agree Not Sure Disagree

SOURCE: STAGE ONE WORKSHOPS — DELOITTE WORKSHOP FEEDBACK

Figure 6.10: Participant feedback on stage two workshops
23 October to 6 November 2013



SOURCE: STAGE TWO WORKSHOPS — DELOITTE WORKSHOP FEEDBACK

Stage 2 Workshop
"The feedback was excellent. Great to see that these workshops are put to good use and taken seriously."
Resident, Regional

The structure of the 'Directions and Priorities 2015 to 2020' consultation document was well-received by stakeholders, and feedback indicated that it added to their ability to engage with the concepts and proposals encompassed within the document.

All feedback received from our 'Directions and Priorities 2015 to 2020' submissions has been considered in developing our Regulatory Proposal and has generally confirmed our approach to key investment areas for the 2015–20 RCP.

Submissions are available on our **TalkingPower.com.au** website.

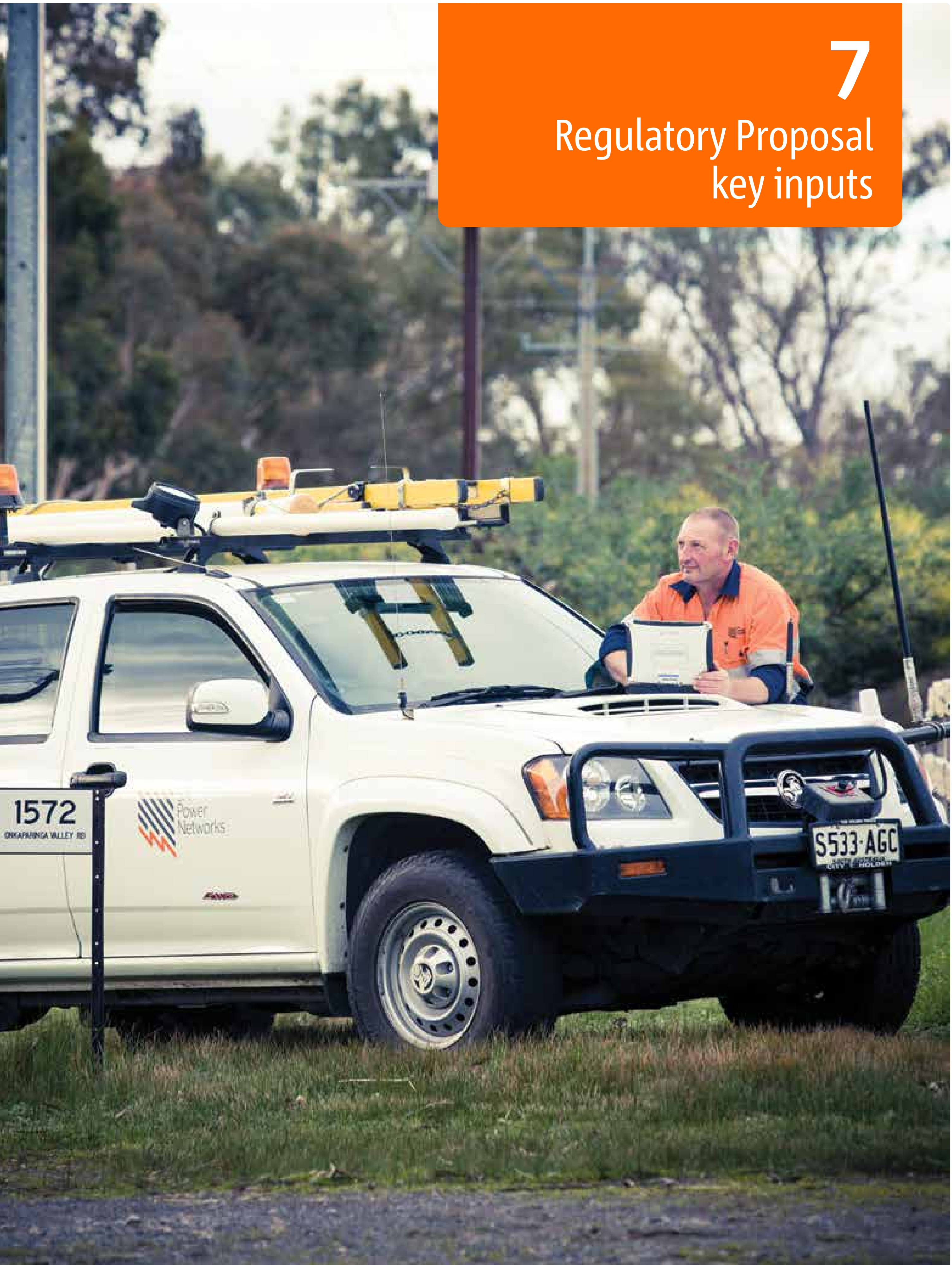
6.7

TalkingPower Customer Engagement Program conclusion — comprehensive and effective customer engagement

In conclusion, we are proud of our TalkingPower program, and believe it represents a breakthrough in terms of effective engagement in our sector. In support of delivery of the program, we have:

- conceived and implemented the most comprehensive stakeholder and Customer Engagement Program ever seen in our sector, using techniques and channels that have not previously been used in Australia;
- conducted extensive research to quantify ongoing priorities for customers, and important shifts in their expectations of us;
- adopted innovative 'design thinking' techniques to work with stakeholders to develop targeted balanced solutions that suit the needs of the community, and for which they are willing to pay. We have then run an exhaustive engagement process on the specific issue of vegetation management, to help align Local and State Government stakeholders to the community's preferences;
- led the industry in terms of creating a detailed technical and operational vision for the longer term future, as articulated in our Future Operating Model 2028, leveraging off the long-running research and trial programs conducted by our Network Innovation Centre;
- developed what we believe to be the most sophisticated and comprehensive customer service strategy in our sector, reflecting the changing expectations of our customers;
- fed our own learnings into the consultation processes of others, to help improve the readiness of our regulatory and institutional frameworks for the future (eg in ESCoSA's SSF consultations, the AEMC's Power of Choice consultations, the AER's Better Regulation consultations, the CSIRO's Future Grid Forum consultations, and so on); and
- conducted exhaustive technical and conceptual modelling to explore the dynamics of new demand side technologies, new pricing strategies, and their interactions.

It is our view that these initiatives and achievements, though intensive and exhaustive, are essential if we are to develop appropriate and optimal plans for the future that align with the long term interests of our customers.



7 Regulatory Proposal key inputs

7

Developing a Regulatory Proposal is always a complex process, yet this Proposal for the 2015–20 RCP is significantly different from previous submissions due to many very significant changes in terms of technology, regulation, markets, economy, energy usage trends and customer expectations, and the transformational implications that arise from them.

This section identifies the key processes and frameworks underpinning the development of this Regulatory Proposal covering:

- customer engagement;
- regulatory obligations;
- distribution network planning;
- Future Operating Model 2028;
- strategic framework;
- Customer Service Strategy 2014 to 2020;
- Expenditure Forecasting Methodology; and
- Framework and Approach.

These key inputs collectively summarise and focus interpretation of the operating environment factors of Chapter 5 and the outcomes of our TalkingPower Customer Engagement Program as described in Chapter 6.

7.1

Customer Engagement Program — TalkingPower

Our Customer Engagement Program has provided us with a greater understanding of the concerns, issues, wants and needs of South Australian electricity customers, now and in the future.

Stage one of the program identified 13 key customer insights. These insights, and their detailed supporting evidence, were evaluated by SA Power Networks' business leaders in stage two of the program and were subsequently incorporated into our business planning processes for the 2015–20 RCP, as appropriate.

The program also made use of advanced stakeholder engagement approaches to further explore two topics (enhanced vegetation management and targeted undergrounding of power lines) that emerged from the core engagement process.

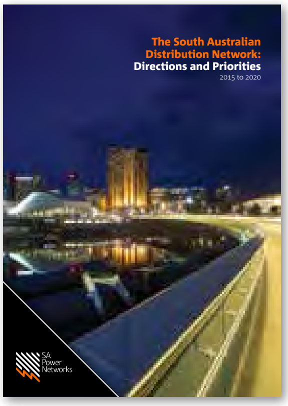
Using 'design thinking' principles, workable concepts suitable for further study were identified in Targeted Strategic Workshops. In these workshops, stakeholders, subject experts and company staff collaborated to review issues and agree on potential options for action, in line with the needs of the community.

The outputs of these workshops were further developed into concept options, with accompanying cost estimates, by staff using the business' detailed knowledge and information sources.

The next step was to translate these concepts into Willingness to Pay survey instruments, to develop statistically valid Willingness to Pay results. We also took steps to ensure 'hardship' customers were properly addressed in the research, as this segment is particularly difficult to reach with common research approaches.

Based on the findings of the Willingness to Pay work, modest customer-supported programs derived from Customer Engagement Program insights were incorporated in our 'Directions and Priorities 2015 to 2020' consultation document which formed the basis of our concluding consultation with customers. The document (see Figure 7.1) contained sufficient detail on issues, objectives, work programs and price impacts to enable valuable and actionable feedback from customers. This feedback has been factored into this Proposal.

Figure 7.1: 'Directions and Priorities 2015 to 2020' consultation document



Refer to Attachment 16.6 for full details of our Customer Engagement Program.

7.2

Regulated obligations

SA Power Networks operates within a comprehensive statutory and regulatory framework, derived from a range of national and state legislation. Depending on the nature of the duty or obligation, a breach or failure on the part of SA Power Networks may result in significant fines or even loss of licence (SA Power Networks operates the distribution network under a licence granted by ESCoSA).

Consequently, the vast majority of SA Power Networks' activities are conducted according to the requirements of the framework.

Key components of our regulatory framework include:

- the **National Electricity** (**South Australia**) **Act 1996**, encompassing the **National Electricity Law** (**NEL**) which sets out the key regulatory institutions of the **National Electricity Market** (**NEM**) and establishes the **National Electricity Objective** (**NEO**);
- the **National Electricity Rules** (**NER**) which govern the operation of the NEM, and provide the regulatory framework for power system security, network connections and access, and pricing for network services. The NER have the force of law, and are made under the NEL;
- the **Electricity Act 1996** which regulates the electricity supply industry in South Australia, requires ESCoSA to licence distribution network service providers, and

stipulates safety and technical standards for electricity infrastructure and electrical installations including preparation and implementation of a **Safety, Reliability, Maintenance and Technical Management Plan** (**SRMTMP**);

- the **Electricity** (**General**) **Regulations**, which support the Electricity Act, and prescribe a range of safety and technical requirements in relation to electricity infrastructure and electrical installations;
- the **Electricity** (**Principles of Vegetation Clearance**) **Regulations**, which support the Electricity Act, and prescribe requirements upon SA Power Networks to inspect and clear vegetation from around power lines;
- the **Australian Energy Market Agreement** (**AEMA**) provides for State and Territory Governments to retain responsibility for developing jurisdictional reliability standards to ensure network security and reliability. In South Australia, ESCoSA sets jurisdictional reliability standards and customer service standards;
- the **Service Standard Framework** (**SSF**) for 2015 to 2020 as set by ESCoSA, which prescribes network reliability targets and customer service responsiveness targets in South Australia;
- our **Distribution Licence** (**Licence**) which requires us to comply with all applicable regulatory instruments, including any technical or safety requirements under the Electricity Act, and to prepare and comply with a SRMTMP, which lays out the safety and technical compliance management framework agreed between the South Australian Office of the Technical Regulator (**OTR**) and SA Power Networks, and which must be approved by ESCoSA;
- the **Electricity Distribution Code** (**the EDC**) which prescribes technical requirements relating to quality of supply for connected customers, application of the jurisdictional reliability and service standards, and the connection of embedded generators;
- the **Electricity Transmission Code** which establishes the standards of service which ElectraNet must meet in providing transmission services in South Australia. Changes to ElectraNet's standards at an exit point may result in flow-on requirements upon the downstream distribution system;
- the **Metrology Procedure** which sets out provisions for metering installations and metering data services; and
- the **National Energy Retail Law (South Australia) Act 2011**, encompassing the National Energy Retail Law (**NERL**) which establishes a **National Energy Customer Framework** (**NECF**) for the regulation of the retail supply of energy to customers, and makes provision for the relationship between the distributors of energy and the consumers of energy.

Aspects of these regulated obligations are identified and expanded upon at relevant points of this Proposal, but the following section elaborates on the central importance of the SSF and the SRMTMP to our business.

7.2.1
Mandatory service standards and network asset management requirements

While all of the components of the regulatory framework are important, some have a far-reaching influence upon the many thousands of activities undertaken by our organisation.

In particular, the **Service Standard Framework** mandates the overall service standards that we must achieve, and our **Distribution Licence** specifies how we must achieve both the service standards and our over-arching safety requirements including those requirements contained within our ESCoSA-approved **SRMTMP**.

Service Standard Framework

ESCoSA is responsible for developing reliability service standards for SA Power Networks[20]. The current Service Standard Framework for SA Power Networks is comprised of three interrelated elements:

- average reliability and customer service standards and targets (set by ESCoSA);
- a symmetrical financial incentive scheme that provides rewards/penalties to SA Power Networks for achievement against reliability and customer service targets (set by the AER); and
- a Guaranteed Service Level (**GSL**) Scheme that provides payments to customers receiving service levels below pre-determined threshold levels within any single year (set by ESCoSA).

Once ESCoSA has established reliability standards, the AER is responsible for assessing the efficient level of expenditure required for SA Power Networks to provide distribution services at the specified standards.

For SA Power Networks' 2015–20 RCP, ESCoSA consulted with the South Australian community to develop the jurisdictional service standards to apply to SA Power Networks. Its initial Issues Paper was released in March 2013, followed by a Draft Decision in November 2013.

On 1 May 2014, ESCoSA released its final decision[21] on the jurisdictional service standards to apply to SA Power Networks for the 2015–20 RCP.

Based on South Australian customers' continuing high levels of satisfaction with average reliability and customer service performance, ESCoSA determined average reliability and customer service standards and targets should continue in order to maintain the average historical levels of service currently provided by SA Power Networks.

Following actual 2013/14 network performance data becoming available, SA Power Networks calculated the proposed network reliability service targets in Table 7.1. These targets were approved by ESCoSA on 8 October 2014 and the EDC has been amended to reflect the new targets from 1 July 2015.

Table 7.1: Proposed electricity reliability performance targets 2015–20

	CBD	Urban	Short Rural	Long Rural	Equivalent Overall
USAIDI (minutes)	15	120	220	300	165
USAIFI (number)	0.15	1.30	1.85	1.95	1.50

Note: The targets exclude reliability performance on Major Event Days.

20 ESCoSA, SA Power Networks Jurisdictional Service Standards for the 2015–20 Regulatory Period, 1 May 2014.
21 ESCoSA, SA Power Networks Jurisdictional Service Standards for the 2015–20 Regulatory Period, 1 May 2014.

Attachment 6.4 contains all the jurisdictional service standards to apply for the 2015–20 RCP.

SRMTMP

The Electricity Act requires a Distribution Licence holder to prepare and comply with a SRMTMP. The OTR and ESCoSA play key roles in annually approving the SRMTMP, and compliance with this plan is a core component of our Distribution Licence.

The SRMTMP determines the governance arrangements, technical standards, inspection processes, and maintenance and construction approaches, among other things, that substantively determine how we manage the vast fleet of assets that constitute the South Australian distribution network, in order to achieve the requisite performance, in terms of network safety and reliability (refer Attachment 7.2).

The standards of performance and the level of network risks to be met are encapsulated in the SRMTMP and have remained essentially unchanged over many years.

7.3

Distribution network planning

As the sole electricity DNSP in South Australia, SA Power Networks is required to provide an annual detailed report that represents our assessment of the network capacity to meet forecast demand over the following five years, together with the possible plans for augmentation of the network. The Distribution Annual Planning Report (**DAPR**) is a publicly available document that is updated annually which provides a high level of transparency regarding key network forecasting, issues and plans for the future.

Our 'Distribution System Planning Report' is the internal document that provides the source data for the publicly available DAPR. This report has recently been updated, based on the revealed weather and demand outcomes from the 2013/14 summer, and any changes will be factored into the updated DAPR which will be published in December 2014. This Proposal has been developed using this latest data. A copy of the 2013 DAPR is available at **TalkingPower.com.au** and at Attachment 7.3.

Our Distribution System Planning Report is included at Attachment 7.4.

As described above, the SRMTMP plays an equally significant role in guiding safe, compliant, effective and efficient management of the assets that comprise the South Australian distribution network.

These documents are key examples of the core technical methodologies that guide SA Power Networks' detailed ongoing planning processes.

7.4

Future Operating Model 2028

As our State's DNSP, SA Power Networks operates and manages billions of dollars of long life assets. That means we need to take the long term view to be sure we make the right decisions on investments that will best serve South Australians for decades into the future.

We are also bound under the terms of the NEO to make those investments 'for the long term interests of consumers'.

Looking into the future, though, has never been more difficult. In the last few years, the pace of change in technology, markets, customer expectations and network usage has accelerated enormously.

SA Power Networks recognises that helping to build a shared vision of our future energy and network needs is essential for our customers and for our business.

That's why we launched our Future Operating Model initiative in 2011. We recently updated it in 2013, and we will continue to regularly review and improve our vision of the long term future. The Future Operating Model is a valuable reference tool for our ongoing planning processes.

To build our Future Operating Model, we started by considering what our customers might be like in 15 years' time. Then, we looked at the type of network services that would be needed by those customers, and how we could deliver on those needs, in terms of the network infrastructure, processes, systems, skills and even job roles we would need to put in place.

As we navigate the emerging period of transformational change in our operating environment, tools like the Future Operating Model will ensure that SA Power Networks is in a position to make the most prudent and efficient investments on behalf of our customers, not just for the next five years, but for the next 10, 15 and even longer.

A full copy of the Future Operating Model (refer Figure 7.2) is available at **TalkingPower.com.au**, and is also included at Attachment 7.7.

Figure 7.2: SA Power Networks' Future Operating Model is an advanced future vision for distribution networks

7.5

Strategic Framework

Our Strategic Framework, discussed in Chapter 3, is a balanced, progressive and robust platform that underpins all of SA Power Networks' short and long term business planning.

The Framework reflects our balanced objectives and strategies, and indicates the business drivers, areas of focus and foundational capabilities that we believe are fundamental to our business.

7.6

Customer Service Strategy 2014 to 2020

We are committed to ensuring that the 'voice of the customer' remains at the centre of our business planning and operations. Our TalkingPower Customer Engagement Program is central to this aim, and has confirmed that customers' expectations of businesses like SA Power Networks are changing consistent with the disruptive changes affecting many other industries.

Our stakeholders and customers have been extensively engaged both in our TalkingPower Customer Engagement Program and the development of our Customer Service Strategy 2014–2020 (refer Figure 7.3). The Customer Service Strategy (**CSS**) represents a transformational approach to customer service in our industry. It is a sophisticated, evidence-based approach to delivering the services and experiences valued by our stakeholders and customers.

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;
- they want more choice in how they interact with us;
- they increasingly value self-service technologies and access to information and services wherever they are;
- value for money retains its importance; and
- more clarity on SA Power Networks' role would be welcomed as well as greater transparency in our operations.

This has culminated in an extensive review of our customer service approach, technology and information platforms. A full copy of the Customer Service Strategy 2014–2020 is available at **TalkingPower.com.au**, and is included at Attachment 6.6.

Our CSS will help guide SA Power Networks through our changing operating environment. Our CSS is now being embedded across the business and has been used extensively in the development of our plans for the 2015–20 RCP.

Figure 7.3: SA Power Networks' Customer Service Strategy 2014–2020

7.7

Expenditure Forecasting Methodology

The Expenditure Forecasting Methodology document describes the methodology which SA Power Networks has used to develop its operating and capital expenditure forecasts for the 2015–20 RCP. The methodology incorporates all regulatory requirements, including the recent NER Chapter 6 changes for the Economic Regulation of Distribution Services[22] and AER Guidelines per the Better Regulation reform program aimed at delivering an improved regulatory framework focused on meeting the long term interests of electricity consumers.

The methodologies outlined in the Expenditure Forecasting Methodology have been used to:
- prepare a forecast of expenditure which reflects the efficient and prudent costs required to achieve the operating expenditure objectives and capital expenditure objectives; and
- include (amongst other things) the methodologies employed by SA Power Networks to forecast demand and the cost of inputs.

SA Power Networks' Expenditure Forecasting Methodology was provided to the AER in November 2013 in accordance with clause 6.8.1A of the NER. A copy can be found at Attachment 7.5.

22 http://www.aemc.gov.au/getattachment/7d29caa7-4599-438c-80f7-094f56599142/National-Electricity-Rules-Version-65.aspx

7.8

Framework and Approach

The AER released its Framework and Approach Paper (**F&A**) for the 2015–20 RCP on 30 April 2014. This paper established the AER's proposed approach as follows:

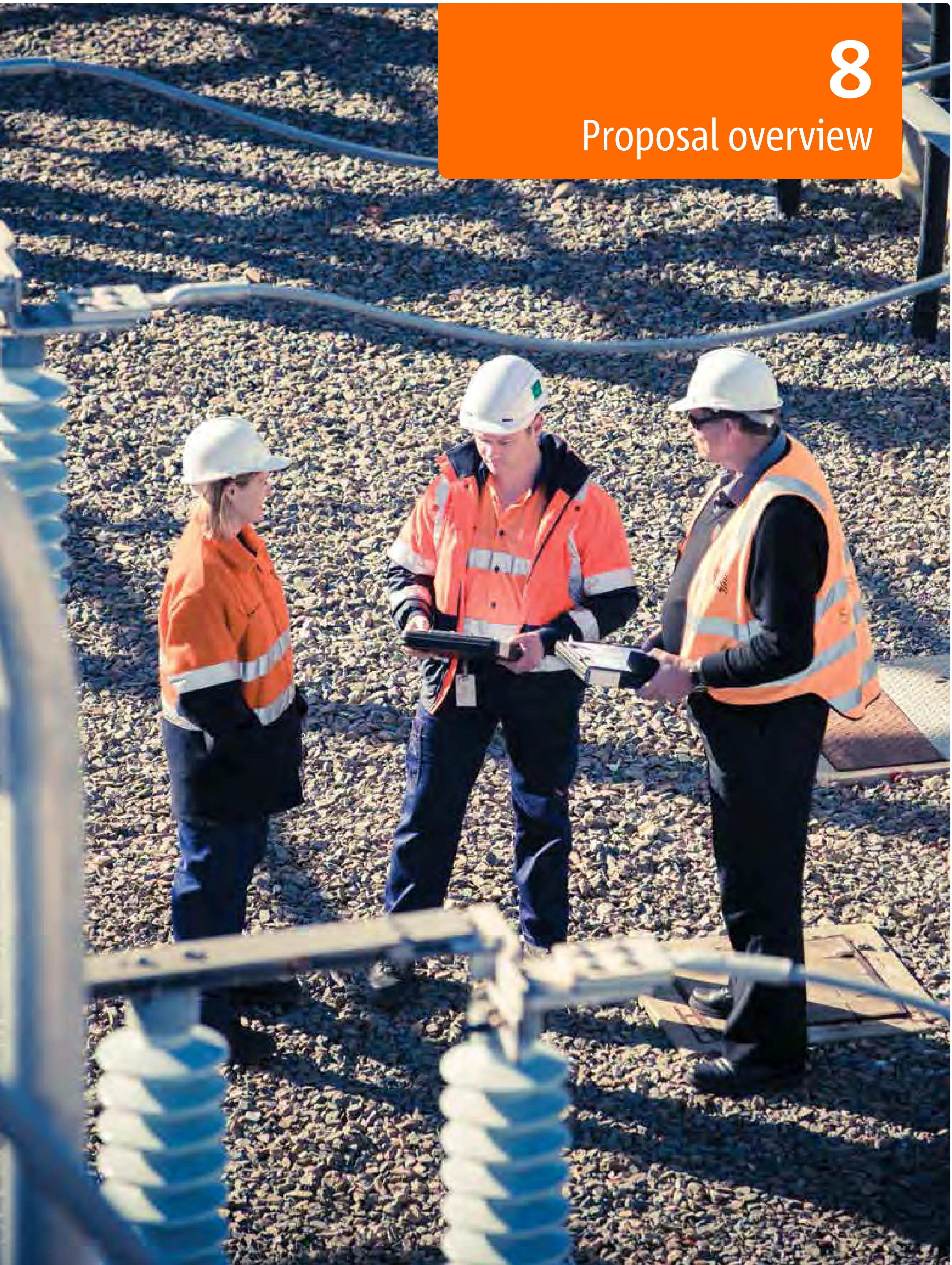
- the form of control mechanism for Standard Control Services will be a revenue control;
- the proposed classification of distribution services is discussed further in Chapter 18 of this Proposal but the F&A essentially proposes the following classifications:
  - Standard Control Services (**SCS**) — incorporating standard network, standard connection and unmetered metering services;
  - Alternative Control Services (**ACS**) — incorporating standard small customer metering services and some legacy metering services associated with large customers; and
  - Negotiated Distribution Services (**NDS**) — incorporating non-standard network, non-standard connection, non-standard small metering, large metering, public lighting and other specific services requested by individual customers;
- the formulae for control;
- that the following incentive schemes will be applied:
  - Service Target Performance Incentive Scheme (**STPIS**);
  - Efficiency Benefit Sharing Scheme (**EBSS**);
  - Capital Efficiency Sharing Scheme (**CESS**); and
  - Demand Management Incentive Scheme (**DMIS**);
- that any Small Scale Incentive Scheme (**SSIS**) will not be applied;
- the Expenditure Forecast Assessment methods to be used by the AER;
- that forecast depreciation be used for rolling forward the regulated asset base to 2020; and
- that 'side constraints' to small customer tariffs be consistent with national arrangements.

The form of control in the AER's Determination must be as set out in the F&A. The AER may only vary the classification of services or the control formulae if unforeseen circumstances justify a departure. All other matters are not binding on the AER, or on SA Power Networks.

This Proposal has been guided by the AER's approach to the above matters which will be discussed further in this Proposal. SA Power Networks is generally supportive of the positions taken by the AER in its F&A and proposes no change on most matters.

However, we are proposing a minor change to the services classification in terms of the addition of three services to the 'Other' category of the NDS listing which will clarify SA Power Networks' ability to recover some specific costs from identifiable individual customers, as discussed further in Section 18.4.

We also note that the AER is intending to apply the National STPIS scheme for the 2015–20 RCP. We currently operate under a variant of this scheme. Alignment to the national scheme will alter the method of calculating performance and the setting of targets for the next RCP. We are proposing arrangements to appropriately transition from the STPIS applying in the current RCP to the national scheme proposed to apply for the 2015–20 RCP (refer Section 23.3).



8
Proposal overview

8

SA Power Networks recognises that the 2015–20 RCP will be the most transformative period of change since the establishment of the NEM.

We continue to be a high performing DNSP, and we have actively positioned our business to be able to respond to regulatory, market, technology and customer developments as they arise, in order to maintain our balanced performance record into the future.

In this environment, more than ever before, our efforts to engage with our customers and stakeholders, to understand their needs and preferences, and to be innovative in developing options and plans to address them, are critical.

We have already discussed the design of our 'Directions and Priorities 2015 to 2020' consultation document which helped readers to understand this complex and changing environment and provided a framework to explain the services we provide to our customers, in turn to enable better feedback.

We have chosen to maintain this customer-focussed approach for this Regulatory Proposal.

Consequently, there are two complementary parts to our Proposal structure.

Chapters 8–17 focus on the services to our customers — where all of our proposed expenditure programs are discussed in the context of our key service areas and the relationship to our Customer Engagement Program.

These chapters demonstrate the increasingly interconnected nature of DNSP programs of work and capabilities. They also strongly reflect the critical role of information systems and processes, and reinforce that DNSP operations require a significantly more sophisticated and integrated approach to optimal service provision than was the case only a few years ago.

Chapters 18–29 focus on regulatory compliance — where all NER-required components of our building block Proposals are provided. All capital expenditures and step change operating expenditures shown in these chapters can be reconciled to corresponding expenditures in Chapters 8 to 17.

Given the structure of the Proposal, it is important for stakeholders to take account of the full range of information provided in the complementary parts of the Proposal.

Table 8.1: Propoal overview

Perspective	Chapters	Key purpose
Proposal overview	8	• summary listing of all key programs of work • associated capital expenditures • associated step change operating expenditures
Services to our customers	9 to 16 Key service areas	• each chapter pertains to one of the key services we provide to our customers (or the things we must do to keep providing them) • regulated obligations • issues related to the key service area • feedback from customers • our evaluation of customer feedback • key programs of work • associated capital expenditures and step change operating expenditures
	17 Service-price trade-off	• overall value of the combined programs of work
Regulatory compliance	18 to 19 Framework and Approach	• classification • negotiating framework • control mechanisms and formulae
	20 Forecast capital expenditure	• capital expenditures by category and program of work • discussion of expenditure forecast methodology, objectives, criteria and factors as appropriate • reconciliation with expenditures in chapters 9 to 16
	21 Forecast operating expenditure	• step change operating expenditures by program of work • base-step-trend derivation of total operating expenditure • discussion of expenditure forecast methodology, objectives, criteria and factors as appropriate • reconciliation with step change operating expenditures in chapters 9 to 16
	22 to 29 Incentives, building blocks and revenue	• uncertainty regime matters • incentive scheme matters • proposed cost of capital • proposed depreciation • proposed tax allowance • revenue and pricing outcomes

8.1

Our key service areas for South Australians

In line with the structure of our 'Directions and Priorities 2015 to 2020' consultation document, chapters 9 to 16 cover the following key service areas (or in the case of Chapter 16, the things we must do to keep providing those key services), as shown in Table 8.2.

Table 8.2: Key service areas

Chapter	Key service areas
Chapter 9	Keeping the power on for South Australians
Chapter 10	Responding to severe weather events
Chapter 11	Safety for the community
Chapter 12	Growing the network in line with South Australia's needs
Chapter 13	Ensuring power supply meets voltage and quality standards
Chapter 14	Serving customers now and in the future
Chapter 15	Fitting in with our streets and communities
Chapter 16	Capabilities to meet our challenges

8.2

Key service area investments drive our Proposal for the 2015–20 RCP

The following table provides a summary reference to SA Power Networks' proposed key programs of work, the associated capital expenditures and step change operating expenditures.

These expenditures for the five years of the RCP are shown in Table 8.3 and can be reconciled to corresponding expenditures in chapters 9 to 16, and to those in chapters 20 and 21. All dollar amounts are in June 2015 dollars.

Operating expenditures shown in Table 8.3 are 'step changes' as per the AER's 'base-step-trend' approach to forecasting operating expenditures. This process is detailed in Section 21.4, and in SA Power Networks' Expenditure Forecasting Methodology.

Table 8.3: Capital and operating expenditures by key service areas

Key service areas and programs of work	Chapter 20 & 21 section references	Capital expenditure $M	Step change operating expenditure $M
Keeping the power on for South Australians (Chapter 9)		**802.8**	**34.7**
Asset replacement			
Lines	20.5.4	553.8	-
Substations	20.5.5	114.1	-
Telecommunications	20.5.6	38.5	-
Kangaroo Island cable	20.6.3	47.2	-
Operational SCADA	20.6.3	25.8	-
Condition monitoring	20.6.3	7.9	-
Environmental management	20.6.4	15.5	-
Substation maintenance (disconnectors)	21.6.2	-	2.4
Staffing — safety operations and asset management	21.6.1, 21.6.2	-	5.8
Asset inspections (no-access poles and underground cable)	21.6.1	-	26.5

Key service areas and programs of work	Chapter 20 & 21 section references	Capital expenditure $M	Step change operating expenditure $M
Responding to severe weather events (Chapter 10)		**58.8**	**9.8**
Harden the network	20.6.2	17.0	-
Managing the effects of aging assets	20.6.2	28.1	-
Remote communities	20.6.2	2.4	-
Outlier low reliability feeders	20.6.2	8.5	-
Micro-grid trial	20.6.2	2.8	-
Migrate telecommunications network	21.6.2	-	7.9
Customer communications — extreme weather	21.6.3	-	1.9
Safety for the community (Chapter 11)		**406.6**	**31.1**
Bushfire risk management program	20.6.6	221.7	-
Network safety program	20.5.8, 20.6.5	107.4	-
Undergrounding at traffic blackspots	20.6.5	77.5	-
Asset and thermographic inspections cycles (BFRA) (5 years)	21.6.1	-	15.6
Vegetation management (BFRA) (net offsets)	21.6.3	-	9.2
Asset inspections safe staffing levels for pre-summer patrols	21.6.1	-	2.8
Customer communications — bushfire and Look Up & Live	21.6.3	-	3.5
Growing the network in line with South Australia's needs (Chapter 12)		**439.2**	**1.3**
Demand driven reinforcement	20.6.1	194.1	-
Strategic reinforcement (incl land)	20.6.1	41.6	-
ETC network reinforcement	20.6.1	14.1	-
Customer connections (net)	20.7.4, 21.6.1	189.4	1.3
Ensuring power supply meets voltage and quality standards (Chapter 13)		**111.7**	**1.0**
Voltage regulation and monitoring	20.6.1, 20.6.3	107.4	-
Flexible load management	21.6.2	4.3	1.0
Serving customers now and in the future (Chapter 14)		**104.8 (SCS) 49.0 (ACS)**	**42.0 (SCS) 86.2* (ACS)**
Billing system replacement project (CIS OV/CRM replacement)	20.8.1	58.4	-
Customer self-service enhancements	20.8.1	8.3	-
Field mobility enhancements	20.8.1	11.1	-
Tariff and metering (applications and equipment) (Standard control services and alternative control services)	20.8.1, 20.9, 21.6.1, 21.13	27.0 (SCS) 49.0 (ACS)	33.8 (SCS) 86.2* (ACS)
Customer support and communication	21.6	-	8.2

Key service areas and programs of work	Chapter 20 & 21 section references	Capital expenditure $M	Step change operating expenditure $M
Fitting in with our streets and communities (Chapter 15)		**46.3**	**22.7**
Power Line Environment Committee	20.6.6	46.3	-
Vegetation management program (more frequent cutting, NBFRA tree removal and replacement, community consultation)	21.6.3	-	22.7
Capabilities to meet our challenges (Chapter 16)		**558.7**	**76.6**
Compliance projects (regulatory, legal, financial management, enterprise asset mgt and environment)	20.8.1,21.6	58.2	14.9
Enterprise technology solutions (data centre, integration, information mgt etc)	20.8.1	34.4	-
Enterprise business solutions (portfolio project mgt, supply chain, people and culture etc)	20.8.1	22.7	-
IT technology management	20.8.1	133.6	-
Advanced distribution management system (ADMS)	20.8.2	11.1	-
TNOC	20.8.2	9.0	-
Emergency services	20.8.2	5.4	-
Property (new depots, maintenance, land and easements)	20.8.3	111.6	-
Fleet (EWP's, commercial and safety)	20.8.4, 21.6.1	146.0	6.1
Technology and systems (licencing, maintenance and support)	21.6.2	-	43.9
Network telecommunications enhancements	21.6.2	-	8.7
Insurance premiums	21.6.4	-	3.0
Plant and tools	20.8.5	26.7	-
Equity raising costs*		4.5	-
Superannuation	20.8.5, 21.6.4	-47.9	-2.4
Total Standard Control Services		**2485.5**	**216.8**
Total Alternative Control Services		**49.0**	**86.2†**
Total		**2534.5**	**303.0**

*Note: Equity raising costs, refer to the AER PTRM for further details.
†Note: Alternative Control Services (ACS) operating expenditures, which relate to provision of meters and meter data services, are not built up through the base-step-trend method, but are shown here for convenience. The amount shown for ACS reflects total operating expenditure.

9
Keeping the power on for South Australians

9

Key points

- The South Australian distribution network covers a vast territory. Most of the network is above ground with 70% of the network assets serving the 30% of customers outside of metropolitan Adelaide.
- Delivering a reliable and safe power supply for South Australians is one of SA Power Networks' most important objectives. South Australia's network remains one of the most reliable in Australia and customers have told us they are satisfied with current service levels.
- We operate under a Service Standard Framework set by the Essential Services Commission of South Australia (**ESCoSA**) which prescribes the reliability and customer service levels that we must deliver to customers. Service levels for the 2015–20 RCP will reflect the historical service levels achieved over the last five years.
- Much of our existing network assets were built in the 1950s, 1960s and early 1970s and are deteriorating and becoming defective. We are proposing $803 million being a prudent level of investment in replacing these assets to ensure the safety of the network meets our regulatory obligations.
- Our existing network is operated and maintained by skilled crews stationed across the State. When the power goes out, these are the people who restore supply to customers — (24 hours a day, seven days a week). We will spend around $187.6 million on emergency response services over the next five years.
- We have worked with customers and key stakeholders to develop a longer term approach to vegetation clearance which will allow us to meet our prescribed legislated requirements and accommodate community expectations on the visual impact and the health of our street landscapes.
- Stakeholders strongly support investment of $47.2 million on a new undersea cable being installed for Kangaroo Island.

9.1

Our regulated obligations

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 consumers with respect to the price, quality, safety, reliability and security of electricity supply (ie the national electricity objective or **NEO**) there are a number of specific regulatory obligations which SA Power Networks is required to meet in 'keeping the power on for South Australians' including:

- the South Australian **Electricity Act 1996** and **Regulations** under that Act — A range of obligations require SA Power Networks to design, install, operate and maintain its infrastructure to be safe including preparation and implementation of a **Safety, Reliability, Maintenance and Technical Management Plan**;
- **Safety, Reliability, Maintenance and Technical Management Plan** (**SRMTMP**) **—** SA Power Networks is obligated under its Distribution Licence to prepare and comply with this plan, which describes the safety, reliability and technical compliance management framework agreed between the South Australian Office of the Technical Regulator (**OTR**) and SA Power Networks, and approved by ESCoSA;
- the SRMTMP contains policy directions, governance, organisational responsibilities and approaches applying to:
  - network operations management;
  - network maintenance (including inspections);
  - network construction;
  - safety, reliability and technical performance indicators; and
  - standards compliance requirements.
- **vegetation clearance** — We must inspect and clear vegetation from around power lines at regular intervals (which cannot exceed three years) in accordance with prescribed requirements under the Electricity Act 1996 and the Electricity (Principles of Vegetation Clearance) Regulations 2010;
- **meet and manage the expected customer electricity demand** — under Chapter 5 of the National Electricity Rules, SA Power Networks has obligations to prepare electricity demand forecasts, identify any network limitations and corrective actions to address those limitations including the requirement for any asset refurbishment or replacement; and
- **electricity Service Standard Framework (SSF) Targets** — We are obligated by our Distribution Licence to meet service standard levels contained in the SA Electricity Distribution Code (**EDC**). These include standards for electricity reliability and a Guaranteed Service Level (**GSL**) scheme. ESCoSA is the jurisdictional body within South Australia that establishes these service standards.

On 1 May 2014, ESCoSA released its decision[23] on the service standards to apply for the 2015–20 RCP. SA Power Networks must use its best endeavours to meet the following reliability standards:

- Unplanned System Average Interruption Duration Index (**USAIDI**) targets (in minutes) for the four feeder categories of: Central Business District (**CBD**), Urban, Short Rural (**SR**) and Long Rural (**LR**). Targets will be based on the average of five years' historical performance excluding Major Event Days (**MED**); and
- Unplanned System Average Interruption Frequency Index (**USAIFI**) targets (number of interruptions) for the same four feeder categories. Again, targets will be based on the average of five years' historical performance excluding MED.

In addition, SA Power Networks will be required to report USAIDI and USAIFI annually for seven geographic areas — Adelaide Business Area (same as CBD), Major Metropolitan Areas, Barossa/Mid-North/Riverland/Murraylands, Eastern Hills/Fleurieu Peninsula, Kangaroo Island, Upper North/Eyre Peninsula and the South East. This will assist customers to compare their experience with historical performance.

Following actual 2013/14 network performance data becoming available, SA Power Networks calculated the proposed network reliability service targets in Table 9.1. These targets were approved by ESCoSA on 8 October 2014 and the EDC has been amended to reflect the new targets from 1 July 2015.

Table 9.1: Proposed electricity reliability performance targets 2015–20

	CBD	Urban	Short Rural	Long Rural	Equivalent Overall
USAIDI (minutes)	15	120	220	300	165
USAIFI (number)	0.15	1.30	1.85	1.95	1.50

Note: The targets exclude reliability performance on Major Event Days.

Under the GSL scheme, customers who experience long or frequent interruptions to supply may be eligible for a GSL payment to acknowledge the inconvenience that the interruption(s) caused. The current GSL scheme will continue for 2015–20, with the following amendments:

- payment levels have been increased to reflect the change in CPI since they were last set in 2009; and
- a new long duration supply interruption GSL payment of $605 has also been introduced which will be paid to customers who experience a single interruption in excess of 48 hours.

23 ESCoSA, "SA Power Networks Jurisdictional Service Standards for the 2015–20 Regulatory Period", 1 May 2014

The GSL scheme for 2015–20 includes the standards in Table 9.2.

Table 9.2: 2015–20 GSL scheme

Requirement	Standard (incl. customer payment if standard not met)
Duration of any single interruption	>12 hours but ≤15 hours ($100) >15 hours but ≤18 hours ($150) >18 hours but ≤24 hours ($200) >24 hours but ≤48 hours ($405) >48 hours ($605)
Frequency of interruptions	>9 but ≤12 interruptions ($100) >12 but ≤15 interruptions ($150) >15 interruptions ($200)

SOURCE: ATTACHMENT 6.4 SA POWER NETWORKS JURISDICTIONAL SERVICE STANDARDS FOR THE 2015–20 REGULATORY PERIOD FINAL DECISION MAY 2014, ESCOSA

9.2

Key issues in 'keeping the power on for South Australians'

Our State has enjoyed the benefits of one of the most reliable distribution systems in Australia over a long period of time (see Figure 9.1). Continuing to deliver a reliable and safe power supply for South Australians is one of SA Power Networks' most important objectives.

However, our network is ageing and the number of identified network defects is increasing, raising the risks to network safety. Our program of asset inspections during the 2010–15 RCP has identified a significant volume of asset replacement work is required to meet our regulatory obligations and to manage the safety of the network. We address these issues through a combination of maintenance (typically operating expenditure) and asset replacement or refurbishment (capital expenditure).

In recent years, the breaking of the 'millennium drought' has caused a significant increase in vegetation growth and the need to increase tree-trimming around our power lines. Unattractive tree-trimming outcomes lead to community concern. In maintaining a safe and reliable electricity supply, better tree-trimming practices are needed to manage community concerns yet meet legal clearance requirements.

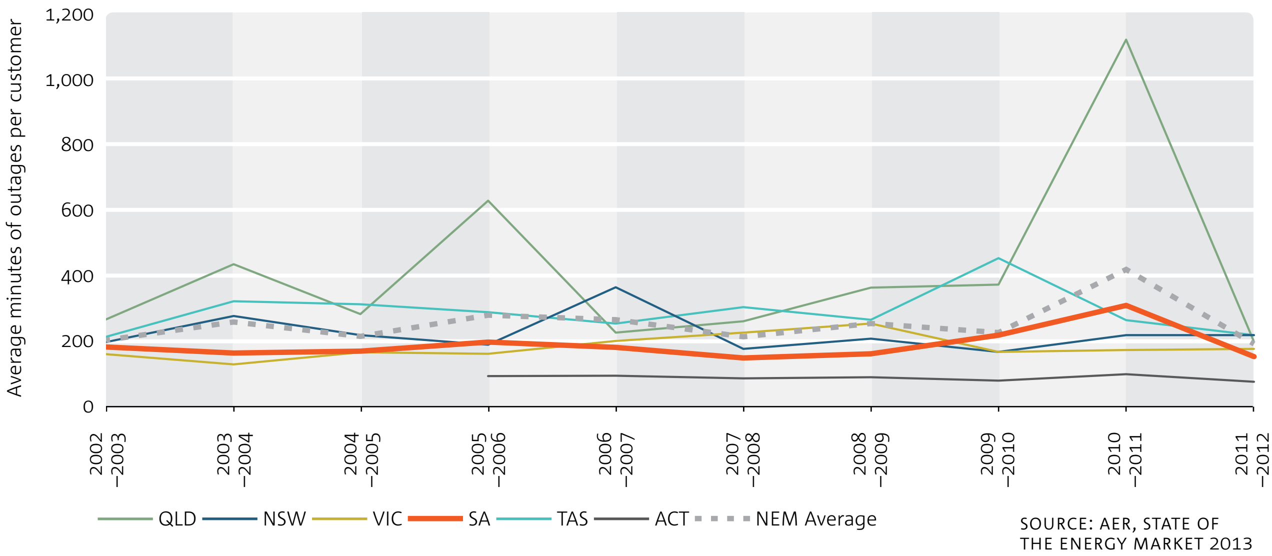
When unplanned supply interruptions do occur, we respond as soon as practicable. Our restoration procedures have been developed over many years and continue to evolve. New technologies and procedures will allow us to restore supply quickly and provide better real time information to affected customers.

In addition to these recurrent works, occasionally significant 'one-off' investments may be the most prudent and cost-effective means to maintain supply. One example of this in the next RCP is the augmentation of supply from the mainland to Kangaroo Island by installing a second submarine cable from Cape Jervis to Penneshaw.

In light of these factors, the key areas of focus in 'keeping the power on for South Australians' are:

1. maintaining the condition of network assets;
2. managing the vegetation impacts on power supply;
3. the timely restoration of supply during outages; and
4. undertaking key investments to maintain the security of supply.

Figure 9.1: Australia-wide distribution network performance — system reliability



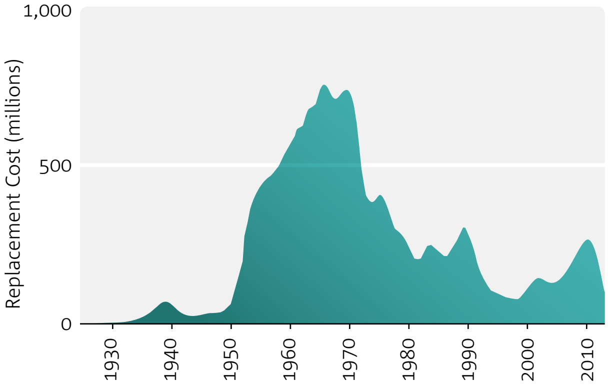
SOURCE: AER, STATE OF THE ENERGY MARKET 2013

9.2.1
Maintaining the condition of network assets

Extending across much of South Australia, SA Power Networks' network is a complex array of electrical assets (including more than 71,000 km of overhead power lines, 17,000 km of underground power cables, 400 zone substations, 73,000 street transformers, 720,000 stobie poles, and millions of fuses and electrical joints). These assets are long-lived, built to deliver maximum electricity demands safely, reliably and to withstand extreme weather conditions.

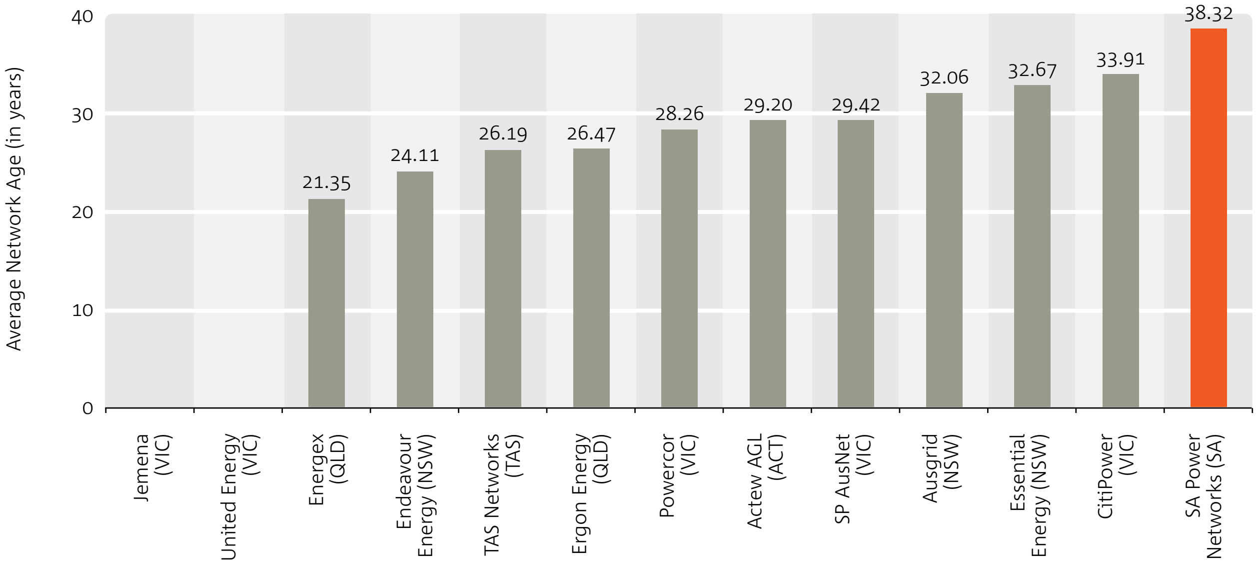
The majority of SA Power Networks' assets were installed in the 1950s, 1960s and early 1970s during the 'electrification of the State' initiated by the Playford Liberal Government. Figure 9.2 which indicates the majority of the replacement cost of our assets relate to assets installed in this period. SA Power Networks has had a continued focus on extracting the most value from its network infrastructure and the historical spend on the replacement of assets has been low. This has resulted in the South Australian distribution network now being the oldest in Australia as indicated in Figure 9.3.

Figure 9.2: SA Power Networks' ageing portfolio of assets



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Figure 9.3: Average Australian distribution network ages



Notes
– Data is sourced from AER. Category Analysis Regulatory Information Notices (RIN) data, published 25 June 2014.
– Category Analysis data supplied to the AER by Jemena was in the incorrect format and has therefore been excluded from this analysis.
– Category Analysis data supplied to the AER by United Energy was inclusive of disposed assets and has therefore been excluded from this analysis.

SOURCE: SA POWER NETWORKS ANALYSIS 2014

The chart indicates the *average* asset life in SA Power Networks' portfolio of assets to be 38 years. Some individual assets will be much older than this average figure. With a typical design life of 40 years, we expect many assets in service will have substantially exceeded their design life and are therefore more likely to have deteriorated, become defective and fail. However asset condition and age, rather than asset age alone, will ultimately determine the need for repair or replacement. Prior to 2010, we historically captured limited data on the condition of our assets, particularly our older assets.

For the 2010–15 RCP, SA Power Networks proposed a particular focus on increasing the expenditure on cost-effectively renewing deteriorating assets, requesting that $467m ($2010) be included in our capital expenditure allowance. The AER did not agree with this proposal and reduced the allowance to $222m ($2010) (a reduction of 52%) on the basis that much of our forecast replacement capex program relied on age based forecasting in addition to our existing condition based forecasts.

The AER considered a condition based asset replacement approach which factors in many asset variables (such as, age, defect history and physical conditions) was prudent and would likely point towards an efficient outcome.

In response to the AER's decision and significant events in other jurisdictions (eg the 2009 Victorian bushfires[24] and serious events in Western Australia[25]), SA Power Networks reviewed its practices into managing its overhead network assets. The review found that the scale of our risks was unclear due to:

- the condition of many assets such as our poles and conductors were not known with an adequate level of accuracy;
- condition assessments and data gathered during inspections varied by inspector; and
- shorter inspection cycles for overhead assets were needed to better understand and manage the risks.

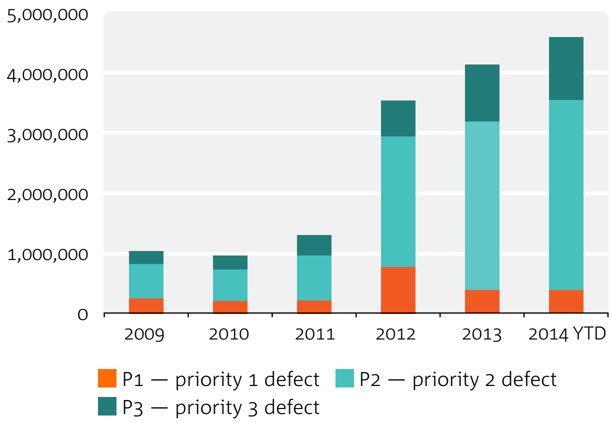
SA Power Networks has now undertaken the following work during the current RCP:

- implemented a more detailed and frequent asset inspection regime (as approved in our 2010–15 regulatory determination);
- captured significantly more detailed data and conducted analysis of pole and conductor failures, and fire starts;
- improved the tools and procedures for the collection of asset condition information on priority asset classes. Our Condition Monitoring and Life Assessment (**CM&LA**) plan (refer to Attachment 9.1) is used to develop detailed asset management plans for each asset class. More recently, we have also introduced Condition Based Risk Management (**CBRM**) models for priority[26] assets;
- increased the training and accreditation requirements for all staff and contracted asset inspectors to Certificate II in Asset Inspection;
- developed mobile data capture tools and business systems to capture asset condition and defect data; and
- improved procedures for prioritising power line asset defects based on risk value.

These changes, in particular the adoption of a CBRM approach, represent best practice and are similar to approaches adopted in other jurisdictions.

The increased inspection rate and adoption of a standardised approach to inspections has resulted in a significant increase in the number of identified defects on the network, in particular on our overhead assets. The volume of these defects continues to grow as we complete more inspections, and has been significantly greater than anticipated by SA Power Networks, resulting in a significant increase in the maintenance risk value (**MRV**) in the network as detailed in Figure 9.4. The resulting network risk level is currently significantly above the risk level approved under our SRMTMP over many years.

Figure 9.4: SA Power Networks' overhead network risk profile for power line network (maintenance risk value, MRV)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

In accordance with our legal obligations to operate and maintain a safe electrical network, our focus during 2010–15 has been to address the highest risks first. In particular, we have targeted the rectification of potential fire start and public safety defects, primarily in the areas of pole, conductor, overhead components and switchgear asset replacement.

We have also significantly increased our asset replacement capital expenditure to manage this growing risk level. By June 2015, we will have spent more than $143 million more on asset replacement capital expenditure than the AER-approved allowance of $239 million (June 2015 $).

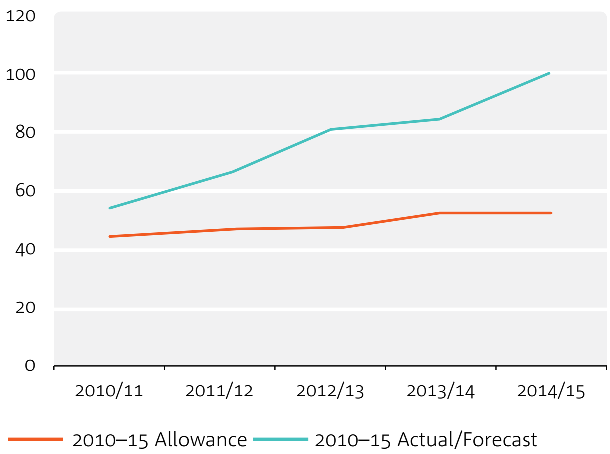
24 In Victoria, the Taskforce findings into the devastating bushfires which occurred in that State in 2009 determined that the poor condition of electricity distribution network assets contributed to the starting of some of these bushfires.

25 In Western Australia, serious asset-related issues, including 'unassisted' pole failures and a conductor failure, have caused fire starts and a fatality.

26 Priority assets consist of poles, conductors, substation power transformers and circuit breakers

Figure 9.5 details the progressive increase in annual replacement capital expenditure throughout the 2010–15 RCP. The profile of this expenditure reflects the lead times required to engage and train additional asset inspectors, perform asset inspections and then prioritise and issue work packages to rectify defects.

Figure 9.5: SA Power Networks' 2010–15 asset replacement expenditure compared to the AER allowance (June 2015, $ million)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

SA Power Networks has performed this additional asset replacement work in a prudent and efficient manner. For example, wherever possible we have implemented the more cost-efficient steel plating repairs of corroded stobie poles, rather than undertaking significantly more expensive complete pole replacement, (steel-plating can extend the life of a pole by up to 50% at around 15% the cost of replacing a pole). When pole replacement has been necessary due to the nature of the defect, competitive tendering amongst our contractors has ensured efficient costs.

With the continued deterioration in the condition of our assets and the ongoing asset inspection program, significant asset replacement works are required to be undertaken over the next 5–15 years. The better quality asset condition information we are now collecting enables improved forecasts of the defects we expect to find over the next RCP and beyond. We have used a range of methods including CBRM, historical trend analysis (multi variable defect forecasting model (**MVDFM**)) and the AER's Repex Model to validate our forecasts. Figure 9.6 outlines the methodologies used in our forecast analysis.

Figure 9.6: Methodologies used to forecast replacement expenditures

	CBRM	Topdown	MVDFM*	Targeted	Historic trend	Repex**
Power line						
Poles	●	○	○		○	○
Conductor	●	○	○		○	○
Other power line				○	●	○
Substation						
Transformers	●	○		●	○	○
Circuit breakers	●	○		●	○	○
Other		○		○	○	○
Telecommunications				●	●	○
Safety				●	●	○

● Indicates forecast basis per asset class (selected methodology)
○ Methodology used

* The multivariable defect forecasting model (**MVDFM**) is an internally developed bottom up forecasting model. This model has been verfied by an independent party, Huegin.
** Repex is not used for all asset classes, only those with asset specific age profiles and replacement history, eg it is not used for bundled assets such as pole tops.

SOURCE: SA POWER NETWORKS ANALYSIS 2014

Without increased efforts to address current and forecast additional defects, SA Power Networks would have to operate our network with an ever growing and unacceptable level of risk to safety and reliability, in breach of both our regulated obligations and the business' historical risk level.

To return our asset portfolio to acceptable risk levels and comply with our regulatory obligations, it is essential that known and forecast asset defects are rectified in a systematic, prudent, timely and efficient manner. In this way we will prudently maintain safety and reliability in accordance with our regulatory obligations and customer expectations, at the least possible life cycle cost.

Over the next RCP we will continue to align our inspection and defect rectification regimes with expected community standards and in line with our regulatory obligations.

9.2.2
Managing the vegetation impacts on power supply

81% of South Australia's distribution network is above ground. Managing trees and other vegetation around overhead power lines is critical to providing a reliable electricity supply and ensuring community safety.

SA Power Networks must comply with prescriptive vegetation clearance regimes that require vegetation to be cleared such that vegetation does not grow, regrow or bend under windy conditions into the 'clearance zone' around the power line. This often results in visual outcomes which do not meet current community expectations.

In the 2005–10 RCP, South Australia was subject to extended drought conditions and consequently vegetation growth around power lines was relatively low.

For the 2010–15 RCP, the AER approved a regulatory allowance of $109 million ($ nominal). This allowance was based on the average historical spend over the previous five years when South Australia experienced the extended drought conditions and below average vegetation growth.

During 2010–11 the 'millennium drought' broke and the prolonged rainfall resulted in a surge in vegetation growth in comparison to that experienced during the drought period. To manage this increased growth, SA Power Networks increased its vegetation clearance activities beyond the regulated allowance, absorbing the increased costs of $17 million incurred during the 2011/12 regulatory year.

On the basis that the growth in vegetation and a doubling of the vegetation clearance required was unexpected and uncontrollable by SA Power Networks, the AER approved an increase in the vegetation clearance allowance of $35 (excluding interest) million for the 2012/13–2014/2015 years (June 2015 $). The increase allowed for higher expenditure in 2012/13–2013/14 to cater for the volume of vegetation clearance required to meet regulated obligations. The AER determined a lower allowance for the 2014/15 year on the basis that they were of the view that a return to average weather and growth would result in lower vegetation clearance volumes. However, we are forecasting expenditure for 2014/15 to be more in line with the 2013/14 spend, which will again exceed the allowance established.

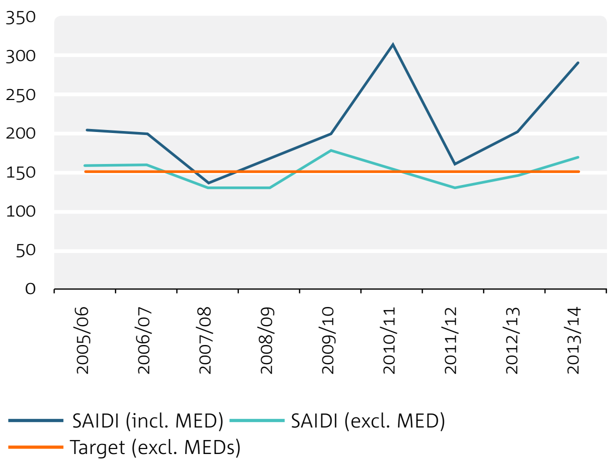
The increased vegetation clearance activities in recent years have heightened community concerns in this area. In 2013 and 2014, SA Power Networks undertook significant consultation with customers, the Local Government Association (**LGA**) and the broader community focussed on achieving better community outcomes whilst maintaining community safety and managing the impact of vegetation on power supply reliability. It is clear that visual amenity of trees around power lines is important in our communities and that our customers and stakeholders want more aesthetic outcomes from SA Power Networks' vegetation clearance practices. We discuss this aspect further in Chapter 16, 'Fitting in with our streets and communities'.

9.2.3
The timely restoration of supply during outages

One of our key roles is to restore power supply when it is interrupted. Providing safe and reliable electricity supply is a 24 hours a day, 7 days a week operation.

Interruptions to power supply can happen at any time of the day or night and typically occur due to the impacts of severe weather events (extreme winds and lightning), vegetation coming into contact with power lines, incidents involving third parties (eg vehicles hitting poles), animals contacting power lines, or equipment failure. Our underlying reliability performance has been stable and consistent with regulatory targets (see Figure 9.7).

Figure 9.7: SA Power Networks network reliability performance with and without MEDs (minutes per annum)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

However, over the last four years South Australia has experienced an increasing number and severity of extreme weather events. The impacts of these severe weather events and actions to address these are discussed further in Chapter 10.

To achieve a timely response for our customers, we have over 800 field employees, operating from 28 operations depots around the State. These employees are supported by an operational fleet of over 600 vehicles.

Our supply restoration procedures and practices have been developed over many years and we are also increasingly adopting new technologies and procedures to restore supply quickly and to provide better real time information to affected customers. Chapter 16, 'capabilities to meet our challenges', elaborates on initiatives we are proposing in relation to workforce, information systems, depot facilities and fleet to continue to deliver these services.

In the 2010–15 RCP we will have spent around $154.8 million on supply restoration activities.

9.2.4
Undertaking key investments to maintain the security of supply

Within any RCP there are specific major investments that are required to be undertaken to keep the power on for customers. In the 2010–15 Regulatory Proposal to the AER, SA Power Networks sought approval for two such key investments being:

- the distribution network developments associated with a new transmission substation required by ESCoSA to ensure the reliability of power supply to Adelaide's CBD and southern suburbs; and
- the installation of a second submarine cable to supply Kangaroo Island — one of Australia's premier tourist destinations — and associated network upgrade and extension work on the Island.

The AER approved $97 million for the work associated with the CBD and southern suburbs power supply. This work was performed during 2011–12 in conjunction with ElectraNet's City West project. Adelaide's CBD now has power supply contingency arrangements appropriate for the State's key commercial district and the southern suburbs have sufficient supply capacity for the foreseeable future.

Despite strong support from the State Government and Kangaroo Island community, the AER rejected the proposed investment for the installation of the new submarine cable and Island network upgrade and extension on the basis that:
"... the project was proposed by ETSA Utilities on the basis of security of supply considerations. The draft decision deferred the project to a timeframe when the project is justified by the need for capacity augmentation as the lowest cost solution."

Figure 9.8: Kangaroo Island undersea cable

The Kangaroo Island undersea cable was installed in 1993 and is approaching the end of its predicted 30 year life. Since the AER's last decision, we have undertaken an extensive review of alternative supply arrangements in the event the existing cable failed, the only feasible option being limited and cost prohibitive local generation. The time to repair the cable could take in excess of 12 months or longer if the cable had to be replaced. During this period our reliability performance to Kangaroo Island cannot be guaranteed. An unreliable supply will adversely impact on tourism, business, the community and local economy. SA Power Networks has undertaken a cost benefit analysis and has determined investing in a new submarine cable before the existing cable fails is the optimal approach.

Extensive consultation conducted with the Kangaroo Island community has confirmed the importance of electricity supply to support tourism and the local economy.

9.3
What our stakeholders and customers have said to us, and our response

9.3.1
Understanding customers' concerns

During the Research Phase of our TalkingPower engagement program we provided some relevant information on key topics and asked our customers and key stakeholders what they expected from SA Power Networks over the next five years and beyond. This was done in the context that any investments and operating costs would be managed within no more than a CPI increase in their network charges. Specifically, with respect to 'keeping the power on for South Australians':

- 88% of customers surveyed were satisfied with their current level of network reliability. However, customers on Kangaroo Island and in the South East were more likely to wish to see their reliability improved;
- survey respondents rated *"Inspecting, maintaining and upgrading the network"* as the most important asset management initiative;
- 88% support SA Power Networks increasing its efforts to monitor the condition of ageing assets;
- 89% support SA Power Networks upgrading and reinforcing the network;
- 89% of customers surveyed supported upgrading and reinforcing areas of the network that are impacted by local demand (higher loadings on the assets), the environment (ie corrosion), and the type of supply to the area (ie single line of supply);
- stakeholders and customers believe it is important to prioritise preventative maintenance to reduce network risks;
- customers clearly understand the need to invest in the network's ongoing reliability to help underpin the South Australian economy;
- 79% of customers supported vegetation management approaches that can improve the appearance of tree trimming, and over time reduce the need for trimming;
- customers support having real time service information including information about restoring supply; and

- customers believe it is important to install a new submarine cable to Kangaroo Island to ensure the island has reliable supply to support tourism and the local economy.

9.3.2 Integrating customer feedback into our business planning process

These customer insights were fed into our planning for the next RCP and a range of key investment options were communicated back to customers and stakeholders for confirmation and comment. These investment priorities were then more broadly consulted on in our 'Directions and Priorities' consultation document. The investments included:

- investment in replacing and refurbishing aged power lines, substations, metering and communications assets when necessary so as to maintain the distribution network reliability and safety performance;
- continuation of our CBRM asset inspection program to collect important data on our assets so that they are optimally replaced;
- invest in integrated Information Technology (**IT**) and communications systems that support the application of modern CBRM approaches;
- continue to work with stakeholders to ensure adequate community engagement about vegetation management;
- continue to invest in depot resources, ensuring we have facilities, staff, fleet and technology in the right place and at the right time to restore supply across South Australia in a timely way; and
- install a new Kangaroo Island submarine cable to secure supply to the island.

9.3.3 Feedback received on our Directions and Priorities 2015 to 2020 consultation document

Responses to the 'Directions and Priorities 2015 to 2020' consultation document with respect to 'keeping the power on for South Australians' were:

Business SA submission:

- "We acknowledge that there is a program of asset replacement over the next few years, but we are still concerned about the indirect impact of a rising RAB on consumers, particularly small businesses."
- "SAPN is doing a solid job of ensuring electricity distribution in South Australia is reliable, even amongst what are often very trying circumstances. As SAPN acknowledges, it is critical that the focus on electricity reliability across the State be maintained as a foundation for economic growth."
- "March survey of members … found that 82.1% of respondents were satisfied with the level of electricity reliability provided by SAPN during the summer heatwave. We acknowledge the trying circumstances during this time and commend SAPN for its efforts in managing expectations as best as possible."
- "Business SA supports the upgrade of the Kangaroo Island undersea cable to ensure electricity reliability for this very important part of the SA economy."
- "We note the significant capital expenditure forecast from 2015 to 2020 on the basis of replacing aging assets. We would expect that an appropriate breakdown of costings per item of capital expenditure will be incorporated into the regulatory proposal and be available to all stakeholders."

Minister for Mineral Resources and Energy submission:

- "Maintaining and investing in the distribution network is important to ensure that safe and reliable electricity is delivered to South Australians."
- "It is important that a new undersea cable (to Kangaroo Island) is installed before the existing cable fails to avoid unnecessary impacts for the community and the Island's reputation as a tourist destination."
- "With respect to the repair and replacement of aging network infrastructure, it is understood that SA Power Networks requires sufficient revenue approved to ensure that South Australian consumers have secure and reliable electricity supply, however, the extent of this expenditure is not clear. Significant expenditure has occurred over multiple regulatory periods and whilst recognising assets were built in the 1950s and 1960s there would be benefit for further information on how much more and for how long funds will be required for this purpose."

Kangaroo Island Council submission:

- "Over the last 18 months we have worked in conjunction with yourselves and the Kangaroo Island Futures Authority to establish the case for the replacement of the 10MW/33KVA undersea supply cable before it fails and we believe that the level of risk and costs and disruption that failure before replacement would impose on our Island Community are simply not acceptable."
- "In addition to the huge costs and risks associated with supporting diesel generation for the long term … we have businesses here that are totally dependent on a reliable mains power supply and could not manage either the risk or the costs associated with long term diesel generation. The impact on our brand has the potential to be significant and we cannot afford for this to happen as a result of premature failure."
- "The cost comparison between planned replacement during the next five year Regulatory period as opposed to replacement at failure has clearly identified the potential for major avoided cost associated with 12–18 months of disruption and we would be hopeful that the Australian Energy Regulator (AER) will recognise this."
- "We fully support the elements of your submission to the AER that apply to Kangaroo Island and we are happy to provide further support/submissions if you feel that they will add additional value."

Council of the Aging (COTA) SA submission:

- "COTA SA's stakeholders, that is older South Australians — whether residential or non-residential consumers — value efficiency and reliability in the delivery of their electricity services. We understand that SAPN is tracking with national trends on both, in part due to previous investment."
- "New service standards are now being put in place for 2015–20. COTA SA understands that there are no new significant measures in these standards, including in reliability. These standards will therefore put no upward pressure on prices."

- "SAPN argues the 'tyranny of distance' in providing reliable service to regional customers. Distance is also a key factor in other jurisdictions: Queensland, the Northern Territory, New South Wales and, indeed, Western Australia. Yet South Australians are paying more for their power distribution in almost all cases. COTA SA understands that the size of the South Australian market, in fact, is sufficient to neutralise the distance factor."
- "Electricity is not a mere consumer product: it is a basic right. Reliable energy is required on a daily basis by all South Australians in both their personal and professional lives. COTA SA is keen to see SAPN pursue a business plan that weighs this socially responsible view with its own requirements for profitability and ongoing quality improvement."

Central Irrigation Trust submission:

- "Whilst we understand the requirement for maintenance of the network we do not see the need for further upgrade of the network particularly in the face of falling demand."
- "As a customer we find reliability of the network satisfactory and do not see the need for further upgrades."
- "We oppose the vegetation management strategy outlined and would like to see a more efficient and cost-effective process employed if one needs to be employed at all."

Residential customer submissions:

- "You've been making money for so long so don't whinge about aging infrastructure."
- "Undergrounding power lines in every location would overcome the maintenance issues and costs that inevitably arise as such as weather conditions, fire and road vehicles hitting poles."
- "The trees are on Council land so get them to trim them or remove them."
- "The Service Guarantee 'fines' should be triple."

9.4

SA Power Networks' response to consultation, and proposed expenditures

Stakeholders' and consumers' responses to the Directions and Priorities document are consistent with the customers' views expressed throughout the Customer Engagement Program. Customers strongly value their current reliability levels and that they are not seeking a reduction in these standards.

While customers have expressed strong support regarding the need for replacing ageing assets, a consistent query from customers is whether the level of expenditure proposed on replacing ageing assets is necessary to maintain reliability.

As outlined above in Section 9.2.1, SA Power Networks has increased its asset inspections (as approved by the AER in its 2010 Determination), during the current RCP to identify the amount of asset replacement work required to cost-effectively deliver on both safety and reliability requirements. Following consideration of the outcomes from the bushfire inquiries in other states, SA Power Networks is proposing to increase the frequency of inspections in bushfire risk areas. We are also including an allowance to undertake targeted inspections programs on those assets that have not been assessed to date. These primarily relate to stobie poles encased in bitumen or concrete and to underground assets that are known to be aged and at risk, but for which exposing, testing and assessing condition require more extensive works at higher costs.

The level of expenditure for asset replacement is supported by comprehensive condition data, detailed engineering analysis and CBRM assessments for priority asset classes (refer Section 20.5). The Proposal also allows for ongoing capability and system developments required to fully embed CBRM methodology into the organisation.

Our proposed expenditure is both prudent and efficient which is further evidenced by SA Power Networks' industry-leading levels of cost-efficiency, as indicated by benchmarking based on the AER's preferred methodologies and using NEM DNSP data published by the AER.

A range of views have also been expressed on the approach to vegetation management ranging from transferring responsibility to councils, to doing nothing extra, to developing a more sustainable long term approach. Clearly, SA Power Networks must continue to meet regulatory obligations for vegetation clearance around power lines. We note the range of views expressed, however, through detailed consultation we have developed a long-term approach to both meet our obligations and enhance our operational arrangements to meet the needs and preferences of the community. This is discussed further in Chapter 15.

Most submissions were silent on the level of resourcing and the location of our field personnel around the State. Business SA did recognise the outstanding work our employees do in restoring and maintaining supply in what can often be trying and difficult circumstances, 24 hours a day every day.

In line with the new 48 hour GSL requirement, we will allow for associated customer payments.

All comments on the Kangaroo Island undersea cable support this investment proceeding.

Table 9.3 outlines the key capital expenditures proposed for the 2015–20 RCP expressed in June 2015 dollars, and Table 9.4 details changes to operating costs above the efficient base year. Further detail on specific capital and operating items can be found in Chapters 20 and 21 of this Proposal.

Table 9.3: Keeping the power on for South Australians — capital expenditures

Item	2015–20 RCP 2015$	Reference section
Asset Replacement		
Lines	553.8	20.5.4
Substations	114.1	20.5.5
Telecommunications	38.5	20.5.6
Environmental management	15.5	20.6.4
Conditional monitoring and NER compliance	7.9	20.6.3
Operational SCADA	25.8	20.6.3
Kangaroo Island cable	47.2	20.6.3
Capex Total	**$802.8m**	

Table 9.4: Keeping the power on for South Australians — operating step changes expenditure

Item	2015–20 RCP 2015$	Reference section
Asset inspections — 'No-Access' poles and underground cable	26.5	21.6.1
Staffing — safety operations and asset management	5.8	21.6
Substation maintenance — disconnectors	2.4	21.6.2
Opex Total	**$34.7m**	

9.5

Benefits to customers

These proposals will provide the following benefits to South Australian customers:

- compliance with regulated obligations;
- prudent and efficient maintenance of the safety of the network;
- prudent and efficient maintenance of the current underlying network reliability performance;
- prudent and efficient management of environmental impacts of oil-filled assets;
- return of the asset portfolio to acceptable risk levels in the longer term;
- sustainable asset inspection regime that enables more accurate risk assessments;
- more effective condition and risk management approaches;
- prudent and efficient supply arrangements for Kangaroo Island; and
- alignment with customer expectations as revealed in our Customer Engagement Program.

10
Responding to severe weather events

10

Key points

- Although underlying levels of reliability for the distribution network are stable, the overall level of reliability, which includes the impacts of Major Event Days (**MEDs**), is deteriorating. MEDs are strongly correlated with severe weather events.
- The number and severity of severe weather events that cause significant damage to our above ground network is increasing.
- Lightning and high winds are the most damaging. Lightning strikes directly damage network equipment, while high winds can blow limbs or whole trees onto power lines. As a result power interruptions can be of long duration, especially for customers in more remote areas where the network is more sparse, and 'radial' lines are longer.
- A regulated Guaranteed Service Level (**GSL**) regime applies in our State. While customers receive GSL payments from SA Power Networks in recognition of the inconvenience of extended interruptions, customers are telling us that we should improve the resilience of the existing above ground network through cost-effective enhancements, and better monitoring, control and automation equipment.
- During the 2010–15 RCP SA Power Networks has commenced work on identifying and hardening parts of the network likely to be affected or which have historically been impacted by severe weather events.
- In the 2015–20 RCP we propose to continue cost effective hardening of specific areas of the network, and to continue to explore opportunities to deploy new technologies and approaches that can improve the reliability and service experience of our customers during severe weather events.

10.1

Our regulated obligations

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 consumers with respect to the price, quality, safety, reliability and security of electricity supply (ie the primary focus of the national electricity objective or **NEO**) there are a number of specific regulatory obligations which SA Power Networks is required to meet in responding to severe weather events including:

- under the Service Standard Framework (**SSF**), we must use our best endeavours to meet the following reliability and customer service targets set by ESCoSA for the 2015–20 RCP:
  - Unplanned System Average Interruption Duration Index (**USAIDI**) targets (in minutes) for the four feeder categories of: Central Business District (**CBD**), Urban, Short Rural (**SR**) and Long Rural (**LR**). These will be based on the average of five years' historical performance excluding Major Event Days (**MEDs**);
  - Unplanned System Average Interruption Frequency Index (**USAIFI**) targets (number of interruptions) for the same four feeder categories. Again, these will be based on the average of five years' historical performance excluding MEDs; and
  - 85% target percentage of telephone calls responded to within 30 seconds;
- the SSF also requires SA Power Networks to report USAIDI and USAIFI annually for seven geographic areas — Adelaide Business Area (same as CBD), Major Metropolitan Areas, Barossa/Mid-North/Riverland/Murraylands, Eastern Hills/Fleurieu Peninsula, Kangaroo Island (no SAIFI standard applies), the South East and Upper North and Eyre Peninsula;
- the SSF requires SA Power Networks to continue to make GSL payments to customers experiencing service below the current pre-determined thresholds, and there will be a new long duration supply interruption GSL payment of $605 for single interruptions in excess of 48 hours;
- the SSF performance monitoring and reporting framework will focus on four particular areas of SA Power Networks' performance:
  - reliability performance outcomes for customers in geographic regions against average historical performance;
  - operational responsiveness and reliability performance during MEDs;
  - identification and management of individual feeders with ongoing low-reliability performance;
  - assessment of the number of GSL Scheme payments made in each geographic region; and
- we must meet or manage the expected demand for standard control services (**NEL**).

10.2

Key issues in 'responding to severe weather events'

South Australia is often subject to severe weather events including lightning storms and high winds which can leave significant damage in their wake. The number and severity of these weather events are increasing and they are the major cause of prolonged interruptions to power supply.

The key areas of focus in 'responding to severe weather events' are:

1. increasing severity and numbers of extreme weather events;
2. organising people and resources to respond to extreme weather events;
3. building a more resilient network for all South Australians; and
4. using technology to deliver timely response and inform customers.

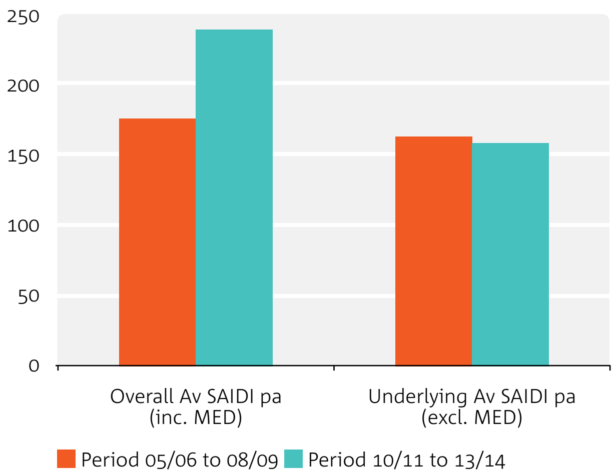
10.2.1
Increasing severity and numbers of extreme weather events

As 81% of our network assets are above ground, they are vulnerable to severe weather and to falling trees or limbs.

When the reliability impact of a weather event exceeds a specified magnitude on a given day, it is deemed to be a MED. These days are typically when storms with lightning and high winds occur.

Although the average underlying reliability performance (ie excluding the effects of MEDs) remains steady, the increasing frequency and severity of weather events has resulted in lower overall reliability. As a consequence, customers are experiencing an additional 65 minutes off supply per year on average for the current RCP in comparison to the previous RCP (refer Figure 10.1).

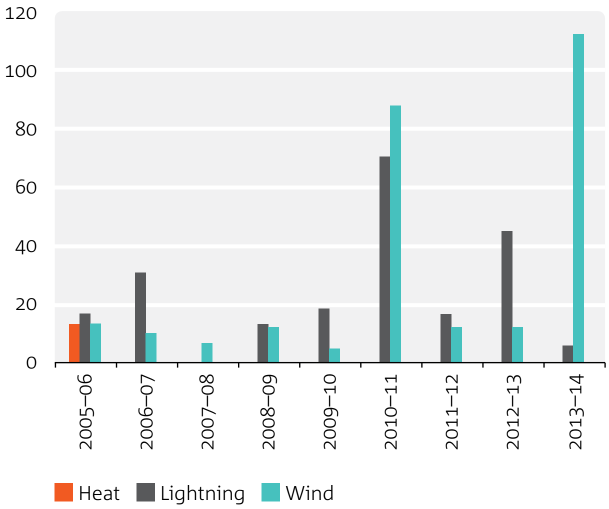
Figure 10.1: SA Power Networks' reliability, with and without MEDs — RCP comparison



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Figure 10.2 shows that the intensity of weather events in terms of their impact on the South Australian distribution network is increasing.

Figure 10.2: USAIDI contribution, minutes (2005–2014)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

In their 'State of the Climate Report 2014', the Bureau of Meteorology and CSIRO[27] predict that the trend of severe weather events is likely to continue. Factors in this forecast include:

- Australian temperatures are projected to increase, with more extremely hot days and fewer extremely cool days;
- an increase in the number of extreme fire-weather days with a longer fire season is expected in southern and eastern Australia;
- average rainfall is projected to decrease in southern Australia, with a likely increase in drought frequency and severity; and
- the frequency and intensity of extreme daily rainfall is projected to increase.

Refer to Attachment 10.2.

The BoM has conducted a climate extremes analysis[28] as it relates to the South Australian distribution network, and found that:

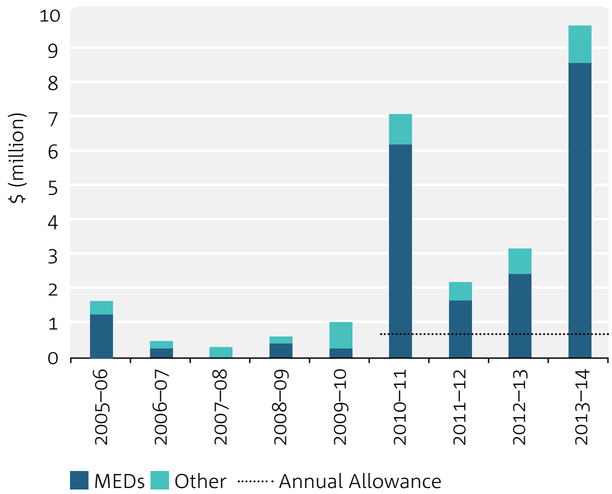
- the trend to a greater number of days with extreme (high) temperatures is likely to continue;
- noting that Fire Danger Rating days have already more than doubled since 2000, increased fire risk is likely to remain or increase further with increased temperatures over the next five to 10 years;
- correlations with the Inter-decadal Pacific Oscillation (related to El Nino and La Nina events) suggest increased thunderstorm and lightning activity may occur in the next 10 to 20 year timeframe; and
- a significant increase in the duration of heat events, which is likely to cause heat stress in trees, has been observed since the late 1990s, suggesting that when wind events do occur, the increased heat stress may result in more material being blown around by winds.

Refer to Attachment 10.2.

Under the ESCoSA Service Standard Framework, customers receive a GSL payment to recognise the inconvenience of being without power for periods greater than 12 hours. In the current RCP, GSL payments, primarily arising from severe weather events on MEDs, significantly exceeded the regulatory allowance for such payments (see Figure 10.3). South Australia is the only jurisdiction in which GSL payments for reliability are paid for MEDs.

In addition to the current GSLs, for the 2015–20 RCP ESCoSA has introduced a new GSL payment of $605 to customers who experience long-term outages of greater than 48 hours. The additional cost of this GSL is estimated to be $1.2 million.

Figure 10.3: GSL payments paid to customers over time (inclusive of MEDs)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

In January 2014, South Australia experienced severe heat waves followed in February by one of the most significant storms to hit the network in recent history. This created widespread outages caused by heat-stressed trees falling on poles, power lines and assets. Some 90,000 customers affected were without power for more than twelve hours and received GSL payments totalling around $6.8 million. The GSL payments for this single event will amount to more than seven times the annual allowance and one and half times the total allowance for the period 2010–15.

In summary, in the current RCP, reliability trends, interruption cause analysis and GSL payment trend analysis all demonstrate the step changes in impacts upon customers and SA Power Networks of severe weather events, with the vast majority of these impacts occurring on MEDs.

It is prudent to expect, at the very least, a continuation of recently observed weather patterns and network impacts for the 2015–20 RCP. This is consistent with the CSIRO and BoM assessments outlined above.

27 Bureau of Meteorology and CSIRO, State of the Climate Report 2014, 2014, p. 15.
28 Bureau of Meteorology, Climate extremes analysis for South Australian Power Network operations, 2014.

10.2.2 Organising people and resources to respond to extreme weather events

As the distribution network covers most of the State our people provide services from our eight metropolitan and 22 regional depots.

Following severe weather events, the time it takes to restore supply is largely affected by:

- the speed with which we can deploy field personnel across the 178,000 km^2 network to respond to the outage;
- making the area safe for the community and our employees (eg when live power lines are brought down) before field personnel start work on restoring supply;
- the extent of the damage in terms of the number and severity of separate instances of infrastructure damage;
- ability to gain access to our assets (eg flooded roads, removing fallen trees, etc); and
- planning to have resources (including materials) available to respond.

Our people work on the network and respond to supply interruptions 24 hours a day, seven days a week, in all weather conditions, to ensure we can restore power as quickly as possible to our residential and business customers.

We also increase the number of operators in our contact centre to meet the large volume of calls from customers reporting outages and seeking updates on restoration times. Customers are now requesting more timely and accurate information on power outages, expected restoration times, and when power is restored. Investing in mobile technologies and supporting business systems will be important to meet the growing customer expectation.

10.2.3 Building a more resilient network for all South Australians

Of our distribution network, 70% of assets serve the 30% of customers who live in regional areas outside the Adelaide metropolitan area. These regional assets were largely established in the post-war 'electrification' period during the 1950s, 1960s and early 1970s. To minimise cost, most regional and rural network power lines were built as radial power lines with no alternative supply paths should there be an interruption.

Customers supplied through radial power lines in locations with challenging geography or environments are more vulnerable to supply interruptions. Locating faults on radial power lines is time consuming because radial power lines may be more than 100 km long and we must often physically inspect the entire line to locate a fault.

One way of reducing the impact of severe weather events for remote customers who are served by long radial power lines is to 'de-radialise' the network supplying those customers. This can be done by, for example, building links from other parts of the network to the radial line, to provide more network supply paths than previously existed. However, under current regulatory arrangements, for small numbers of remote customers it is often deemed inefficient to improve network performance in this way.

On the other hand, 'hardening' of the network can be thought of as a class of targeted initiatives that improve the durability of existing assets during severe weather events. They do not involve construction of line duplications or links, but still have the effect of either improving resilience of the network to the effects of severe weather events or improving restoration timeliness.

During the 2010–15 RCP SA Power Networks has commenced identifying and progressively and cost-effectively hardening parts of the network likely to be affected or which have historically been impacted by severe weather events. We have commenced the installation of polymer insulators on our power poles in place of ceramic insulators to improve network resilience against lightning strikes on the most vulnerable sections of the network. Such approaches are efficient ways of improving the resilience of the network to severe weather events, and can reduce long outage times.

While GSL payments are intended to go some way to compensating such remote customers for loss of supply, particularly under MED conditions, there are customer and community circumstances that challenge the idea that GSL payments alone are an appropriate response. In particular:

- **sizeable remote rural communities** — There are a number of communities where customer service performance consistently does not meet regional SSF targets, mainly due to the impact of severe weather events upon their single radial line supply which can be up to several hundred kilometres long, and where the impacts of poor supply on the local economy may be particularly damaging (this can be the case for tourism-driven communities, for example); and
- **customers supplied by outlier 'worst performing feeders'** — Under ESCoSA's SSF, SA Power Networks reports on 'worst performing feeders' which repeatedly record high frequency or duration of supply interruptions. They are generally single wire earth return (**SWER**) lines located in remote parts of the State. This category of feeders can be represented under a statistical distribution curve, and the tail end of such a distribution demonstrates that there are some customers who receive extraordinarily poor service.

For both of these circumstances, customer feedback over a long period of time has strongly indicated that GSL payments are insufficient to compensate for the inconvenience of very poor service outcomes and that appropriate action should be taken to address network performance. Investments in improved technologies such as polymer insulators are ways to address some of these issues.

10.2.4
Using technology to deliver timely response

In the current RCP, SA Power Networks has been combining proven network technologies and efficient fault response systems in order to manage the growing impact of severe weather events on MED reliability across our network. This includes working towards progressively integrating our systems to address the information requirements of our customers and customer facing employees.

We are in the early stages of trialling new technologies in network monitoring and control that will help us to identify faults in remote areas of the network and to respond more quickly.

During the current period we have been investing in a new advanced distribution management system (**ADMS**). This system will be fully implemented by 2015 and combined with the targeted investment in new network equipment we will be able to remotely control devices and reduce the impact of severe weather events. Specifically, we will focus on:

- automating targeted parts of the network to reduce the duration of power interruptions; and
- remotely controlling the network configuration (where possible) during and after a severe weather event.

The success of these technological improvements in the medium term depends on us maintaining the network's underlying reliability performance in the short term through a program of efficient inspections, maintenance, replacement, refurbishment and reinforcement.

In the longer term, we expect emerging technology may provide other approaches to bolstering the supply reliability for customers in remote areas of the network, or with specific supply challenges. One area that is discussed in our Future Operating Model and has particular promise is 'micro-grid' technology. SA Power Networks considers that micro-grids have high potential for successful application in terms of improving our response to severe weather events for certain regional and remote customer groups.

The term micro-grid typically refers to a customer or section of the network that is normally connected to the broader network, but can be 'islanded' from that network and operate stand-alone under certain circumstances.

Although micro-grids have existed for many years, both for individual customers and communities, they have generally relied on diesel generation as their prime means of electrical supply when islanded. These types of systems are prohibitively expensive other than for customers that place a very high value on reliability of supply (for example, hospitals and data centres) or for customers that are remote and for which a grid connection is uneconomic.

With the continued advancement of solar PV distributed generation capabilities, and anticipated cost reductions in battery storage technologies, new opportunities are arising for more cost effective micro-grids. With significant local generation already in place (solar PV) and if a material number of customers also take up battery technology, this investment by individual customers may be able to be leveraged to maintain supply to an entire community should that community's network connection fail.

SA Power Networks considers that the potential for a micro-grid solution to mitigate power supply issues during severe weather events warrants investigation.

10.3
What our stakeholders and customers have said to us, and our response

10.3.1
Understanding our customers' concerns

During the Research stage of our TalkingPower engagement program we provided some relevant information on key topics and asked our customers and key stakeholders what they expected from SA Power Networks over the next five years and beyond. This was done in the context that any investments and operating costs would be managed within no more than a CPI increase in their network charges. Specifically, with respect to 'responding to severe weather events' the TalkingPower program confirmed that:

- 88% of customers support further protecting the network to harden against lightning and storms;
- customers in poorly-served/low reliability network areas understand the causes of the level of reliability that they receive (eg due to the long radial feeders in remote locations);
- 89% of customers surveyed supported upgrading and reinforcing areas of the network that are impacted by local demand, the environment, and the type of supply to the area;
- customers support our efforts to identify emerging issues early and prioritise preventative maintenance to mitigate risk;
- rural customers and stakeholders would like to see a more robust network supplying their communities to ensure our network services support the development of their communities; and
- the communities of Elliston on the Eyre Peninsula and Hawker in the Flinders Ranges (two communities which have a significant history of very poor performance influenced by their location) reaffirm their need for a robust network supplying their communities.

10.3.2
Integrating customer feedback into our business planning process

These customer insights were fed into our planning for the next RCP and a range of key investment options were communicated back to customers and stakeholders for confirmation and comment. These investment priorities were then more broadly consulted on in our 'Directions and Priorities 2015 to 2020' consultation document. The investments included:

- undertake more frequent inspection of the most vulnerable parts of the network and undertake preventative maintenance and replacements;
- continue investing in hardening sections of the network most vulnerable to lightning and storms;
- address specific radial line constraints where it is cost effective to do so;
- design and build new assets for the network that are sufficiently robust for the changing operating environment and more onerous operating conditions; and
- continue to invest in facilities, staff, fleet and technology to ensure timely restoration of supply across South Australia.

10.3.3
Feedback received on our 'Directions and Priorities 2015 to 2020' consultation document

Responses to the 'Directions and Priorities 2015 to 2020' consultation document with respect to 'responding to severe weather events' were:

Minister for Mineral Resources and Energy submission:

- "Maintaining and investing in the distribution network is important to ensure that safe and reliable electricity is delivered to South Australians."
- "While I am encouraged that SA Power Networks forecasts the price impact will be relatively small, in light of community concerns, SA Power Networks is encouraged to consider any opportunities for expenditure savings that could provide real decreases in electricity prices. This could mean reconsideration of any non-critical projects."

COTA SA submission:

- "SAPN has consistently argued that the level of capacity must meet the demand in peak periods (predominantly in extreme hot weather within the summer months). This position partially drives the case for capital investment."

Residential customer submissions:

- "Undergrounding power lines in every location would overcome the maintenance issues and costs that inevitably arise as outside hazards, such as weather conditions, fire and road vehicles hitting poles."
- "The issues inherent in existing electricity infrastructure that have presented to me are an inherent part of the impacts of severe weather events and safety in relation to bushfire. Both connected to the way trees are managed around power lines by our home."
- "About common power failure in the Flinders Ranges — if you had put better insulators long ago there would not have been the problems over the last 4 years."

Central Irrigation Trust submission:

- "As a customer we find reliability of the network satisfactory and do not see the need for further upgrades, changed bushfire prevention activities or hardening of the network against lightening [sic] and storms."

10.4
SA Power Networks' response to consultation, and proposed expenditures

Throughout our Customer Engagement Program, stakeholders and customers have 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 type of supply to an area is susceptible to failure (eg radial line supply).

The Directions and Priorities consultation feedback added little new information to this assessment, except for Business SA who expressed support for economic development, which can be a consideration in improvements in our response to severe weather events for specific communities, and the Central Irrigation Trust which does not support hardening the network against severe weather events.

The Directions and Priorities consultation proposals did incorporate a number of targeted de-radialisation projects. The cost-benefit analyses of these types of projects are heavily sensitive to the number of customers who will benefit, and the extent of the reliability improvement achievable.

In this context, we note the Minister's call for re-consideration of non-critical projects, in the interests of community price concerns. Consequently, we have considered a long term approach to targeted de-radialisation projects, reducing the number to be undertaken over the next five years (reduction of $31.6 million in capex over the five years).

In summary, our proposed program of expenditures for this service area include projects that:

- cost-effectively harden the sections of the network that are most vulnerable to the impact of lightning and storms during MEDs, in order for SA Power Networks to meet its SSF and license obligations regarding reliability, customer service and safety. These include projects selected based on:
  - the number of interruptions and impact to customers during MEDs;
  - customers whom are worst served during storm events;
  - storm-related conductor failures; and
  - storm-related fire starts from electrical infrastructure;

- improve reliability performance to Elliston and Hawker by:
  - hardening against lightning and storms those sections of network that supply these two remote communities; and
  - installing remote monitoring and control on the lines supplying the towns;
- improve service to our worst served customers and communities by targeting 31 'outlier' low reliability feeders for remedial initiatives that will harden their network sections against impacts from lightning and storms; and
- trial new and emerging opportunities to use micro-grid technology to more cost-effectively maintain supply to poorly served rural and remote communities fed by long, radial lines, who commonly lose supply due to severe weather events.

The micro-grid trial would be based on the application of the technology to an individual community with a view to determining its broader applicability across the network. If successful, such a solution might ultimately be used for a variety of purposes, including:
- maintaining supply to Country Fire Service Bushfire Safer Places under high bushfire risk conditions;
- deferring network augmentation of long rural lines by utilising local storage to lop network peaks; and
- potentially, decommissioning such lines that would otherwise require replacement owing to age and condition.

Again, all of these initiatives will be targeted based on historical MED events, so it is expected the overall MED impact and storm related safety events will be reduced whilst maintaining future underlying reliability performance at current levels.

Table 10.1 outlines the key capital expenditures proposed for the 2015–20 RCP expressed in June 2015 dollars, and Table 10.2 details changes to operating costs above the efficient base year. Further detail on specific capital and operating items can be found in the referenced sections of this Proposal.

Table 10.1: Responding to severe weather events — capital expenditures

Item	2015–20 RCP 2015$	Reference section
Harden the network against storms	$17.0	20.6.2
Remote communities service improvement	$2.4	20.6.2
Outlier low reliability feeders	$8.5	20.6.2
Micro-grid trial	$2.8	20.6.2
Reliability program — managing the effects of aging assets	$28.1	20.6.2
Capex Total	**$58.8m**	

Table 10.2: Responding to severe weather events — operating step changes expenditure

Item	2015–20 RCP 2015$	Reference section
Migrate telecommunications network	7.9	21.6.2
Corporate Communications — extreme weather	1.9	21.6.3
Opex Total	**$9.8m**	

10.5

Benefits to customers

These proposals will provide the following benefits to South Australian customers:
- compliance with regulated obligations;
- prudent and efficient management of the current underlying network reliability performance;
- reduction in number and duration of supply interruptions experienced by customers due to (increasing) MEDs;
- increased capability to deploy innovative technologies to address MED resilience;
- more secure, effective and efficient operational communications for major service events;
- more effective and timely communications before and during major service events; and
- alignment with customer expectations as revealed in our Customer Engagement Program.

11 Safety for the community

11

Key points

- Safety for the community and our employees is our highest priority.
- Recent events and trends indicate that bushfire risks are increasing in Australia.
- Given the proximity of our network to the community along with the real threat of bushfire and road safety hazards impacting our infrastructure we are committed to improving the risks to safety for all our customers, employees and contractors, and the community.
- SA Power Networks has stringent bushfire risk management systems, and these will continue to be improved to match good electricity industry practice. These include inspection regimes, design and construction standards, and tree trimming/ vegetation clearance practices.
- Consistent with community expectations, we will work towards 'CFS Bushfire Safer Places' having reliable power supplies.
- There is also community concern about road safety risks which arise when power poles are in close proximity to road users and there is support for targeted undergrounding or relocation of poles to reduce these risks.
- Our customers have told us that they have a high level of concern about community safety throughout South Australia and want SA Power Networks to undertake preventative maintenance and strategic investment to drive reliability, manage risk and support economic growth while focusing on public safety.

11.1

Our regulated obligations

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 consumers with respect to the price, quality, safety, reliability and security of electricity supply, (ie the primary focus of the national electricity objective or **NEO**) there are a number of specific regulatory obligations which SA Power Networks is required to meet in 'safety for the community' including:

- we have a duty under **Section 60 of the Electricity Act** to take reasonable steps to ensure that our infrastructure complies with, and is operated in accordance with, the technical and safety requirements imposed under the **Electricity** (**General**) **Regulations**, and is safe and safely operated;
- the **Electricity** (**General**) **Regulations** require us to adhere to various listed standards (eg Australian and Industry Standards) for infrastructure;
- we must prepare and comply with a **Safety, Reliability, Maintenance and Technical Management Plan** (**SRMTMP**), which lays out the safety and technical compliance management framework agreed between the South Australian Office of the Technical Regulator (**OTR**) and SA Power Networks, and is approved by ESCoSA. Key elements of the SRMTMP are:
  - relevant policy directions, governance, organisational responsibilities and approaches as they apply to network:
    - operations management;
    - maintenance management (including inspections);
    - construction management;
    - safety, reliability and technical performance indicators; and
    - standards compliance requirements; and
- we must inspect and clear vegetation from around power lines at regular intervals (which cannot exceed three years) in accordance with prescribed requirements, under the **Electricity Act** and **Electricity (Principles of Vegetation Clearance) Regulations 2010** (**Regulations**).

11.2

Key issues in 'safety for the community'

Safety for the community is of paramount importance to SA Power Networks. We are committed to achieving the highest standards of safety for all our customers, employees and contractors, and the community.

There are a number of areas in our network that pose specific safety risks to the community. The overall health and condition of our assets is an important contributor to safety and we have well developed maintenance, refurbishment and replacement activities and programs of work to address the overall condition of our network assets.

A key consideration is the community safety risks posed by the environment and position in which our assets are located, that is in bushfire risk areas and adjacent to roads.

The key areas of focus in 'safety for the community' are:

- mitigating the rising risks of bushfire ignition by power infrastructure;
- managing risks from older deteriorating infrastructure; and
- addressing road safety hazards from power poles.

11.2.1
Mitigating the rising risks of bushfire ignition by power infrastructure

South Australia has always faced significant risks from bushfires. The State often experiences hot, dry and windy weather conditions, creating high fire danger in areas that may be tinder-dry and fuel-rich. Some of the highest risk areas include those close to regional centres, in the Adelaide Hills and southern coastal areas.

SA Power Networks' assets are associated with on average 67 fires per annum across South Australia. More recently, the major bushfires in NSW, Victoria and Tasmania have heightened the community focus on mitigating bushfire risks.

This community concern is appropriate, as the risk of ignition of bushfires by power infrastructure is both major and increasing.

Catastrophic impacts of bushfire ignition by power lines

The second most catastrophic bushfire in Australia's history was Ash Wednesday, which in 1983 resulted in the death of 28 people in South Australia and 47 people in Victoria.[29] In South Australia, the fires burnt more than 159,000 hectares of land and caused damage to several hundreds of homes.[30] The total estimated cost of damage caused by the fires was in excess of $300 million.[31]

In 2005 on a day of extreme fire danger, fires that burnt on the Eyre Peninsula caused an estimated $41 million in damage[32], burning more than 78,000 hectares of land and causing the death of 9 people.

In today's context, the potential impact of a bushfire ignition as a result of the failure of SA Power Networks' assets could be devastating, both in terms of the potential loss of life or injury, and the potential property damage which may be sustained.

Using a bushfire risk database based upon input data produced by the Bushfire Cooperative Research Centre (**CRC**), and consideration of the impact of the 1983 Ash Wednesday fires as well as the 2005 Port Lincoln fire, Willis Risk Services (**Willis**) has undertaken an analysis of the estimated maximum probable loss associated with a fire as a result of ignition within SA Power Networks' electricity

29 The most devastating fire was Black Saturday in Victoria in 2009.
30 Country Fire Authority, Ash Wednesday Factsheet, accessed 30 May 2014 at http://www.cfa.vic.gov.au/fm_files/attachments/kids_and_schools/fact-sheets/fs_ash-wednesday.pdf.
31 Figure quoted in today's terms. Insurance Council of Australia, Historical Disaster Statistics, accessed 30 May 2014 <http://www.insurancecouncil.com.au/industry-statistics-data/disaster-statistics/historical-disaster-statistics>.
32 Figure quoted in today's terms. Insurance Council of Australia, Historical Disaster Statistics, accessed 30 May 2014 <http://www.insurancecouncil.com.au/industry-statistics-data/disaster-statistics/historical-disaster-statistics>.

distribution network. That analysis has revealed that the maximum probable loss associated with a single major fire within the Adelaide Hills region alone is estimated to be $500m.

Given that the extreme conditions necessary to fuel an intense fire could equally give rise to multiple fires occurring on the same day, Willis estimates that the maximum probable loss associated with fires within the SA Power Networks service area is approximately $1 billion, refer Attachment 11.3, SA Power Networks Australia Limited Bushfire Modelling.

The reasonableness of these estimates may be verified using the recent claims made as a result of the Black Saturday bushfires of 2009. On 15 July 2014 it was reported that the largest of the Black Saturday class actions has been settled, subject to Court approval, for an amount of approximately $500m[33]. Media reports record that a Victorian electricity distribution business (SP AusNet) will contribute approximately $378.6m to the settlement, a contribution which is estimated to approximate up to 35% of the value of the estimated 10,000 claims.

The risk of bushfire ignition by power lines is increasing
An analysis of climatic trends sourced from the Bureau of Meteorology (**BoM**), suggests that in South Australia, the conditions most conducive to intense and damaging fires are occurring on a more frequent basis.

Since the 1970s there has been an increase in the incidence of extreme fire weather and a longer fire season across large parts of Australia, with the largest increases occurring in the south east and inland, refer to Attachment 10.2, Bureau of Meteorology and CSIRO, State of the Climate Report 2014. Continued increases in extreme temperatures are likely, evidenced by the fact that over a period of about 55 years the number of record hot days across Australia has doubled.[34]

Warming trends noticeable across Australia continue to apply when looking specifically at South Australia. The BoM estimates that over the past few decades average day and night time temperatures have increased by approximately 1 degree Celsius.[35] Further, the annual number of days of extreme temperatures, with an average daily temperature exceeding 32.5 degrees Celsius, has not only continued to increase but since 2000 has doubled.[36] The BoM estimates that this pattern of extreme weather is likely to continue over the next five to 10 years.[37]

In addition, analysis following the Victorian Bushfires Royal Commission (**VBRC**) indicates that electricity-caused fires are more likely to occur on extreme fire danger days.

33 http://www.news.com.au/national/victoria/black-saturday-victims-to-get-500m-payout-after-settlement-reached/story-fnii5sms-1226988896884
34 Bureau of Meteorology, *Climate extremes analysis for South Australian Power Network operations*, 2014, page 4.
35 Bureau of Meteorology, *Climate extremes analysis for South Australian Power Network operations*, 2014, page 4.
36 Bureau of Meteorology, *Climate extremes analysis for South Australian Power Network operations*, 2014, page 4, 12–13.
37 Bureau of Meteorology, *Climate extremes analysis for South Australian Power Network operations*, 2014, page 13.

Based on results of an analysis by The Nous Group, the likelihood of fires starting from electrical assets on Black Saturday was approximately two to three times higher than on any other days, including total fire ban days (see Figure 11.1).

Figure 11.1: Fire starts per day (last five years)

Type of day	CFA fires reported	Fire starts at electrical assets	%
All days	40	0.4	1.0
Non total fire ban days	30	0.3	1.0
Total fire ban days	280	2.2	0.8
Black Saturday	592	10–20	1.7–3.4

SOURCE: THE NOUS GROUP

The fact that electricity-caused fires are more likely to occur on extreme fire danger days, coupled with projections of more frequent and extreme high temperatures, means that, absent mitigation, not only is the number of electricity-caused fires likely to increase, but those fires are likely to be more intense and potentially cause more damage.

In addition, the age and condition of the South Australian distribution network is a key factor that elevates bushfire ignition risks even further. Most of SA Power Networks' network was built between 40 and 65 years ago. Much of the network has therefore been exposed to environmental conditions for a significant period of time. Although the assets are long life assets, assets that are greater than 40 to 65 years of age are more likely to be experiencing deterioration and are therefore at greater risk of failure, relative to assets exposed to the same environmental conditions over a shorter period of time. This risk is most appropriately managed through regular asset inspections and remediation where necessary, as was discussed earlier in Chapter 9, 'Keeping the power on for South Australians'.

These factors reinforce the importance of undertaking prudent investment to maintain the safety and operation of electricity assets to reduce their likelihood of starting fires.

How we have traditionally managed bushfire risks
SA Power Networks currently manages bushfire risk by managing (trimming) vegetation, programmed inspections, maintenance and using predetermined criteria to prioritise the replacement of overhead power lines 'at risk' with either insulated conductors or undergrounding. Note that moving overhead power lines underground is very costly and is therefore a highly targeted approach for specific circumstances.

In extreme and catastrophic bushfire risk situations we also have the authority to turn the power off (legislated after the devastating Ash Wednesday bushfires) to protect lives and property.

Vegetation management plays a significant role in management of bushfire risks. SA Power Networks has a continual vegetation management program including tree trimming around power lines to minimise the risks of starting bushfires in high-risk areas, and also of electric shock, power interruptions and damage to power lines.

We currently spend about $36 million annually on managing vegetation. The parameters for tree-trimming set under the Regulations are prescriptive and provide limited discretion to SA Power Networks. We recognise that statutory requirements such as inspection regimes and clearance zones around trees often lead to unattractive tree trimming.

SA Power Networks acknowledges that there is a need to move away from a one-size-fits-all approach and work towards a more sustainable and long-term approach that may include strategic removal and tree replacement and improved tree trimming practices. This is discussed further in Chapter 15, 'Fitting in with our streets and communities'.

Recent developments and investigations relevant to management of bushfire risks

We continue to review our risk management programs to maintain our focus on reducing the risk of bushfires on extremely hot, dry and windy days. This includes looking at improvements being made interstate as well as examining State Government strategies and customer preferences as they pertain to these risks.

This reflects our duty to take reasonable steps to ensure that our distribution system is safe and safely operated (Section 60(1) of the Electricity Act) and to maintain and operate our distribution system in accordance with good electricity industry practice (NER Clause 5.2.1(a)). These duties require 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. SA Power Networks continually monitors these industry developments and learnings to ensure that it is discharging these dynamic and evolving duties.

***Victorian Bushfires Royal Commission** (**VBRC**)* — After the catastrophic bushfires of Black Saturday in February 2009, the VBRC was established to conduct an extensive investigation and report on the cause, response, preparation for and impact of the fires.

In its report the VBRC identified the role that electricity asset failures play in starting fires and called for "major changes" to the operation and management of ageing electricity infrastructure. It determined that it was "time to start replacing the ageing infrastructure" and called on both the State of Victoria and the distribution businesses to invest in infrastructure improvements in order to "substantially remove one of the primary causes" of catastrophic fires in Victoria, 2009 Victorian Bushfires Royal Commission, Final Report Summary July 2010.

A number of the VBRC's recommendations have been adopted through amendments to Victoria's electricity safety legislation and regulations, in effect mandating a new Victorian standard of practice, which is funded by reference to a new funding mechanism which provides financial incentives for fire mitigation-based investment.

Power Line Bushfire Safety Taskforce — The Victorian Government established the Power Line Bushfire Safety Taskforce (**PBST**) to review the outcomes of the VBRC, and advise it of the strategies that would maximise value from the implementation of the VBRC's recommendations relating to the replacement of power lines and reclosers. The PBST also made its own recommendations on strategies to reduce the number of fires started from power lines.

The PBST adopted a "precautionary-based approach" to determine what should be done to reduce bushfire risk from power lines. Under that approach, it adopted "all reasonable practicable precautions" having regard to balance between the magnitude of the risk and the effort required to reduce the risk. Refer to Attachment 11.7, Power Line Bushfire Safety Taskforce, Final Report, September 2011.

SA Power Networks considers that the PBST's recommendations are likely to now constitute **good electricity industry practice** in Australia.

After allowing for differences between Victoria's and South Australia's electricity infrastructure (eg in terms of pole and cross-arm construction materials, and associated earthing systems), key recommendations of the PBST still apply to the distribution network in South Australia. Those recommendations have been carefully analysed in assessing which mitigation strategies should be selected for inclusion in SA Power Networks' program of bushfire mitigation strategies. Refer Attachment 11.8 Recommended Bushfire Risk Reduction Strategies for SA Power Networks, Jacobs.

Country Fire Service Bushfire Safer Places — Other developments in South Australia also have a bearing on potential directions for the future. For example, following the Black Saturday bushfires, the Country Fire Service (**CFS**) launched the Bushfire Safer Places initiative, where certain settlements and precincts are designated places of relative safety in extreme fire conditions. People may shelter there during forecast catastrophic fire danger levels and during bushfires. Ensuring the security of electricity supply in these designated places is vital during emergency situations.

Customer preferences — Throughout SA Power Networks' Customer Engagement Program, customers and stakeholders overwhelmingly reinforced that the community places very significant priority on bushfire risk management issues, as well as those relating to network inspections, maintenance and upgrades that have an impact on bushfire safety outcomes.

For example, 90% of respondents to our on-line survey supported increased inspection, maintenance and construction standards in bushfire risk areas in order to minimise the probability of fires starting from power lines, and 90% supported investment to ensure more reliable power supply to CFS Bushfire Safer Places.

During our Customer Engagement Program a targeted workshop on undergrounding power lines was held and customers and subject matter experts together explored alternative strategies and approaches. Customers recognise that the high cost of underground power lines makes extensive undergrounding prohibitive, however there was a common view that more could be done with a prudent strategy that places greater emphasis on longer term solutions, managing community safety risks and enhancing stakeholder participation.

Our engagement extended to collaboratively developing options based on stakeholder-derived principles, and then testing price sensitivity via Willingness to Pay discrete choice modelling research on the various options for targeted undergrounding of power lines.

Figure 11.2 shows the level of Willingness to Pay (black line) for each combination of improvement initiatives tested. The orange bars represent the associated incremental annual amount customers would be asked to pay. The chart is organised into four groups, corresponding with the four levels of undergrounding (0, 135, 270 and 375 kms) tested.

Within each of these groups there are four or five different vegetation management options (removal and replacement of inappropriate vegetation under power lines in spans subject to inspection and clearance: 0%, 2.5%, 5%, 8% and 10% of spans). The green 'accepters' line shows the percentage of respondents who accepted all improvement options presented to them relating to high bushfire and medium bushfire risk areas.

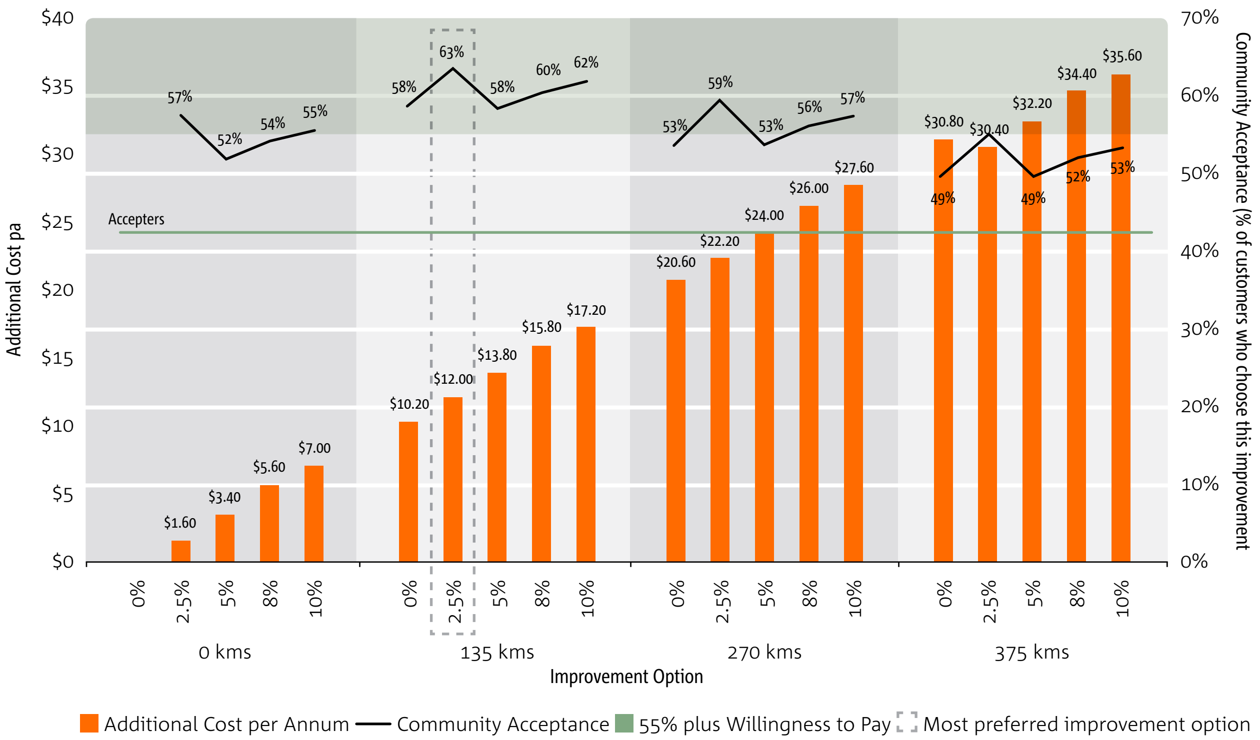
At least 55% of the community were prepared to pay for ten of the nineteen improvements tested in bushfire risk areas. The grey dotted box highlights the most preferred improvement option in bushfire risk areas which encompassed a program of 135km of undergrounding combined with 2.5% removal and replacement of inappropriate vegetation for additional bush fire safety benefits. 63% of customers surveyed were willing to pay an additional $12 annually.

More detailed customer segmentation information can be found in the Willingness to Pay research report Attachment 6.8.

SA Power Networks' balanced approach

In 2012 SA Power Networks engaged independent consultants Sinclair Knight Merz, now Jacobs, to report on SA Power Networks' bushfire mitigation management practice vis-à-vis other DNSPs, and to advise what, if any, strategies it should adopt to maintain pace with industry trends.

Figure 11.2 Bushfire Risk Areas — Willingness to Pay by specific improvement tested



SOURCE: THE NTF GROUP, SA POWER NETWORKS TARGETED WILLINGNESS TO PAY RESEARCH — RESEARCH FINDINGS, THE NTF GROUP PTY LTD, JULY 2014.

Jacobs reviewed and reported on:

- SA Power Networks' current practices and procedures for bushfire risk management;
- SA Power Networks' fire start history in order to establish root causes of bushfire starts;
- current industry bushfire risk management practices by and initiatives of DNSPs in Australia; and
- the findings of investigations into bushfires conducted by the VBRC and the PBST.

Jacobs recommended options which provide the greatest prospect of reduction in fire starts given a prudent economic investment, as a basis for ongoing consultation, project and Proposal development by SA Power Networks. These are outlined further in Section 11.4.

11.2.2
Managing risks from older infrastructure

SA Power Networks has some unique risks within the network that need to be addressed to ensure ongoing safety for the community and for our people operating the network. For example in parts of the Adelaide CBD network ageing cable joints in manholes are at risk of failure. Failure of these cable joints presents a safety risk to the public due to the potential for manhole covers to become dislodged and cause personal injury. In addition, SA Power Networks proposes the replacement of a range of network equipment that is considered unsafe to the public or unsafe to operate.

11.2.3
Addressing road safety hazards from power poles

Across metropolitan and regional South Australia, SA Power Networks' assets line thousands of km of roads, many of which have high traffic flows. The potential for vehicles to crash into infrastructure is greater at intersections, sections of road subject to high traffic volumes and difficult sections of road.

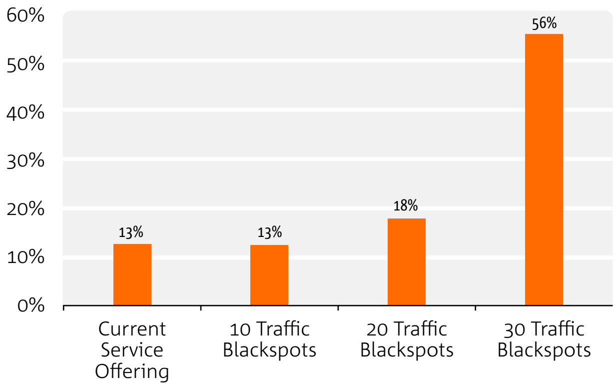
Over the years some South Australian roads have been made wider to handle increased traffic flows. As a result, the road surface is closer to our poles, increasing the attendant road safety risk. These risks can be reduced by relocating poles or placing power lines underground and removing redundant poles.

In our Customer Engagement Program's targeted workshop on undergrounding, customers raised significant concerns regarding these risks. Recognising the prohibitive costs of widespread undergrounding, they indicated a preference for reducing community safety hazards by a targeted approach to undergrounding power lines and poles at high risk locations.

Our engagement extended to collaboratively developing options based on stakeholder-derived principles, and then testing price sensitivity via Willingness to Pay research on the various options for targeted approaches to undergrounding power lines.

The Willingness to Pay discrete choice modelling research, Figure 11.3, identified that the majority (56%) of those surveyed were willing to pay up to an additional $9.40 annually for a targeted program of undergrounding power lines to address thirty traffic blackspots (comprised of approximately 15 intersections and 15km of road), thereby reducing the potential for vehicle collisions with stobie poles. There was 74% support for at least twenty blackspots.

Figure 11.3 Willingness to Pay by specific improvement tested — traffic blackspots



Service Improvement	Additional Cost Per Annum
10 Blackspots	Increase of $3.00
20 Blackspots	Increase of $6.20
30 Blackspots	Increase of $9.40

SOURCE: THE NTF GROUP, SA POWER NETWORKS TARGETED WILLINGNESS TO PAY RESEARCH — RESEARCH FINDINGS, THE NTF GROUP PTY LTD, JULY 2014.

More detailed customer segmentation information can be found in the Willingness To Pay research report in Attachment 6.8.

11.3
What our stakeholders and customers have said to us, and our response

11.3.1
Understanding our customers' concerns

During the Research Stage of our TalkingPower engagement program we provided some relevant information on key topics and asked our customers and key stakeholders what they expected from SA Power Networks over the next five years and beyond. This was done in the context that any investments and operating costs would be managed within no more than a CPI increase in their network charges. Specifically, with respect to 'safety for the community', our TalkingPower Customer Engagement Program confirmed that:

- 90% of customers supported increased inspection, maintenance and construction standards in bushfire risk areas in order to minimise the probability of fires starting from power lines;
- 90% supported investment to ensure more reliable power supply to CFS Bushfire Safer Places;
- customers have a preference for asset management, preventative maintenance and strategic investment to drive reliability, manage risk and support economic growth while focusing on public safety;

- customers have a high level of concern about community safety throughout South Australia;
- customers want us to consider improvements in public safety and reliability in asset planning where long term benefits can be realised;
- customers support investment in bushfire management initiatives to ensure that CFS Bushfire Safer Places have continuous power under critical conditions; and
- they recognise that while complete undergrounding of the electricity network is cost prohibitive, additional selective undergrounding for higher risk areas (eg bushfire risk areas and road safety black spots) is desirable (as revealed through extensive Willingness to Pay research).

11.3.2
Integrating customer feedback into our business planning process

These customer insights were fed into our planning for the next RCP and a range of key investment options were communicated back to customers and stakeholders for confirmation and comment. These investment priorities were then more broadly consulted on in our 'Directions and Priorities' consultation document. The investments included:

- progressively reinforce power supply to the South Australian CFS Bushfire Safer Places;
- increase the frequency of inspections and maintenance in Bushfire Risk Areas (**BFRAs**) to further reduce risk;
- invest in a tree removal and replacement program;
- build power lines less prone to starting fires in high risk areas;
- implement key findings from the Victorian Bushfires Royal Commission Final Report where they are appropriate for South Australian conditions;
- continue managing vegetation clearance to ensure compliance in BFRAs while working towards a more sustainable and long-term approach;
- increased community consultation on vegetation management approaches;
- targeted program of undergrounding to reduce the potential for vehicle collisions with stobie poles;
- invest in community education to improve safety awareness around power lines; and
- invest in strategies to address and prioritise the risks posed by older assets to the community.

11.3.3
Feedback received on our 'Directions and Priorities 2015 to 2020' consultation document

Responses to the 'Directions and Priorities 2015 to 2020' consultation document with respect to 'safety for the community' included:

Business SA submission:

- "We acknowledge the good intention of SAPN's focus on addressing road safety hazards from stobie poles and its aim to target busy main roads and intersections with a modest programme of undergrounding works to reduce the potential for vehicle collisions."
- "Issues of road safety relating to stobie poles require analysis much broader than whether or not removing the stobie pole results in an optimal outcome given the impact of accidents potential moving to the next barrier, be that a building, tree or otherwise."
- "However modest SAPN's proposed spending, road safety is ultimately the responsibility of the State Government and SAPN should not spend time or resources on such issues when its costs are ultimately borne by the end users of electricity, including small businesses."
- "Furthermore, consideration should be given to how SAPN access Motor Accident Commission funds for such expenditures."

Residential customers submission:

- "Undergrounding power lines in every location would overcome the maintenance issues and costs that inevitably arise such as weather conditions, fire and road vehicles hitting poles."
- "The trees are on Council land so get them to trim them or remove them."

11.4

SA Power Networks' response to consultation, and proposed expenditures

Throughout our Customer Engagement Program, stakeholders and customers have expressed support for programs aimed at:

- building power lines less prone to fire starts;
- ensuring CFS Bushfire Safer Places have continuous power supply;
- undertaking more frequent inspections and maintenance in BFRAs;
- undergrounding power lines where additional safety benefits can be identified (eg in high bushfire risk areas (**HBFRAs**) or road safety blackspots); and
- continuing asset management investment to drive reliability and manage risk.

The Directions and Priorities consultation feedback added little new information to this assessment, and it is important to note that no concerns were expressed with respect to any of our proposed bushfire risk management directions.

However, Business SA expressed its view that undergrounding of assets at traffic blackspots would be more appropriately undertaken by other entities. In response to this feedback, SA Power Networks has undertaken further discussions with the Motor Accident Commission and the State Government Department of Planning, Transport and Infrastructure (**DPTI**), to further develop collaborative opportunities. These discussions have confirmed their support for SA Power Networks' initiative, and we propose to establish a protocol for targeting the work program to achieve maximum community benefit. On the issue of whether it is appropriate for SA Power Networks to undertake such a program, it is our view that this is a case of legitimate community concern over a class of our assets that directly and negatively impacts on an important aspect of community safety. On the basis that the proposed treatment program is modest and targeted, and that extensive Willingness to Pay research demonstrates significant majority support for the initiative, we have retained the program in this Proposal but have modified the level of investment to twenty blackspots over the next five years.

The major component of the proposed expenditures relates to bushfire risk management programs which:

- secure the electricity supply for 12 (of 65) CFS Bushfire Safer Places by undergrounding sections of power line in HBFRA's and install remotely operated reclosers at prioritised locations;
- generate the greatest level of reduction in fire start risk, relative to the investment involved; and
- ensure SA Power Networks continues to operate in accordance with good electricity industry practice, having regard to comparative networks elsewhere in Australia.

The bushfire program includes initiatives that:

- replace high risk lines with more secure power supply for 12 CFS Bushfire Safer Places which are designated places of relative safety in extreme fire conditions. The CFS Bushfire Safer Places initiative is a key State response to heightened community and Government bushfire risk concerns that followed the Black Saturday disaster in Victoria. This work received near universal support in our Customer Engagement Program;
- progressively replace ageing reclose devices with modern SCADA devices which can be operated remotely. Reclosers are a form of network protection. When faults occur, they operate by turning off power and then restoring power once a transient fault has cleared. Power will be turned off permanently if the fault does not clear;
- replace Rod Air Gaps (**RAGs**) and Current Limiting Arcing Horns (**CLAHs**) which are obsolete over-voltage protection technologies that have inherent ignition risks. This program involves a targeted replacement of highest risk of RAGs/CLAHs with modern surge arrestors in HBFRAs;
- investigate the potential for future use of ground fault neutralising technology (**GFN**). GFN is a relatively new earth fault protection technology with potential major future benefits in fire start reduction. Installed in substations, the equipment rapidly detects and reduces earth fault currents to avoid overvoltage events, which reduces ignition risks in downstream infrastructure. The program involves a trial of the technology, in two substations located in HBFRAs;
- continue the reconstruction of metered mains. Metered mains were built in the 1950s to early 1970s on very large rural properties. Ownership of these low voltage power lines is inconsistent, and the uncertainty as to who is responsible for them has led to a reduced level of investment in their maintenance over time. Many metered mains are in HBFRAs, and remediation of the highest risk mains to current engineering standards is a priority. SA Power Networks' program will resolve ownership and remediate high risk assets. We have already commenced this process;
- upgrade back-up protection on rural Single Wire Earth Return (**SWER**) power lines which do not meet current standards. SA Power Networks will undertake a 10 year program to review all rural SWER power lines and implement appropriate back-up protection solutions, targeted to SWER lines in BFRAs;
- in high bushfire risk locations, eliminate fire start risk by undergrounding targeted sections of power line or removing trees. Customers have clearly indicated their preference for use of undergrounding as a means of reducing community safety hazards on a targeted basis, recognising the prohibitive costs of widespread undergrounding. Willingness to Pay research, based on options developed by SA Power Networks following advice from expert community stakeholders, has shown that a measured program of undergrounding in HBFRAs to reduce fire start risk is supported by a significant majority of customers. The undergrounding program will eliminate fire start risk over 135km of power lines in HBFRAs (inclusive of work on CFS Bushfire Safer Places);
- increase in the frequency of inspection of assets consistent with current Australian practices to mitigate bushfire risk by providing an opportunity to repair or replace deteriorating assets before they fail. The frequency of asset inspections historically conducted by other Australian DNSPs is generally twice that undertaken by SA Power Networks across BFRAs, and SA Power Networks will increase the frequency of its periodic asset inspections from 10 years to five years combined with a pre-summer patrol as a cost effective solution which is considered consistent with the three year program, to align with the Victorian standards established after the Black Saturday bushfires; and
- expand the use of thermographic imaging inspections in BFRAs to help identify potential conductor and joint faults. To improve the effectiveness of these special-purpose inspections at modest additional cost, SA Power Networks will increase the frequency of thermographic imaging on its 11kV networks in BFRAs during summer peak load periods.

The program to address safety priorities arising from a range of network and aged assets condition matters includes initiatives that:

- remediate high risk manholes and cable joints in the CBD underground network. The CBD is supplied via an underground power network consisting of manholes, ducts, cables and joints. There are approximately 5,500 high risk cable joints that were installed from 1961 to 1995. These cable joints are increasingly failing and in some instances, have dislodged manhole covers. This program aims to remediate the highest risk cable joints located in manholes, in high pedestrian areas and install measures to manage high fault levels;
- continue to remediate power lines to address mechanical defects or planting of inappropriate species of vegetation beneath the power lines, that over time have resulted in inadequate clearances. Specified conductor clearances are required under the Electricity Act and Regulations to ensure the safety of the public and our employees;
- remediate 78 transformer stations at Elizabeth which can no longer be maintained as the operation of their switches has been banned as they are unsafe. These works are a continuation of a long term program to manage the first underground network in South Australia, established between 1948 and 1969, that commenced prior to the current RCP and is planned to be completed by 2025;

- continue a long term program to remediate unsafe elements of aged substations that do not comply with the Electricity Act and Regulations. Items include removal of asbestos, upgrade of substation security and fencing to prevent unauthorised entry, and remediating substation lighting;
- undertake asset replacement programs in substations which include remediation of substation earthing to prevent potential electric shock and remediation of unsafe inoperable overhead switchgear and instrument transformers;
- remediate high risk CBD switchboards and ring main unit (**RMU**) infrastructure. This program aims to remediate high risk, unsafe 33kV and LV substation switchboards and unsupported telecommunications and monitoring systems;
- continue the long term program to remediate ground level switchgear infrastructure which is inoperable due to risk of explosion; and
- remediate unsafe corroded telecommunications structures and maintain aged emergency switching communications to ensure critical communications are available at all times.

The program to relocate or underground assets at twenty prioritised traffic blackspots involves:

- the undergrounding of assets to remediate dangerous intersections and road sections where vehicles have collided with SA Power Networks' infrastructure resulting in injury or death of one or more persons, on more than one occasion;
- to ensure prudency of the program, a working group consisting of SA Power Networks, Motor Accident Commission and DPTI personnel has been formed and protocols and criteria for identifying optimum sites will be established. An initial assessment has identified two sites for remediation; and
- future sites will be determined by the working group in accordance with the protocol, targeting the work program to achieve maximum community benefit.

Table 11.1 outlines the key capital expenditures proposed for the 2015–20 RCP expressed in June 2015 dollars, and Table 11.2 details changes to operating costs above the efficient base year. Further detail on specific capital and operating items can be found in the referenced sections of this Proposal.

Table 11.1: Safety for the community — capital expenditures

Item	2015–20 RCP 2015$	Reference section
Bushfire Risk Program		
Replace reclosers with SCADA-enabled reclosers	17.9	20.6.6
Replace CLAHs and RAGs with surge arrestors	12.3	20.6.6
Test and install Ground Fault Neutralisers	11.9	20.6.6
Re-align back-up protection	18.4	20.6.6
Reconstruct metered mains	32.7	20.6.6
Targeted undergrounding in HBFRAs (incl. BSPs)	128.6	20.6.6
Network Safety Program		
Remediate high risk manholes and joints	23.3	20.6.5
Remediate high risk lines and Elizabeth transformer stations	14.3	20.6.5
Remediate high risk substations	39.7	20.6.5
Remediate high risk CBD substations	14.1	20.6.5
Remediate high risk switchgear	10.7	20.6.5
Remediate high risk telecommunications assets	5.3	20.6.5
Targeted undergrounding at traffic blackspots (20)	77.5	20.6.5
Capex Sub-Total	**$406.6m**	

Table 11.2: Safety for the community — operating step changes expenditure

Item	2015–20 RCP 2015$	Reference section
Asset and thermographic inspection cycles in BFRAs (5 years)	15.6	21.6.1
Vegetation management BFRA (net of offsets)	9.2	21.6.3
Asset inspections — two person crews for pre-summer bushfire inspections (safety)	2.8	21.6.1
Customer communications — bushfire and Look Up and Live	3.5	21.6.3
Opex Total	**$31.1m**	

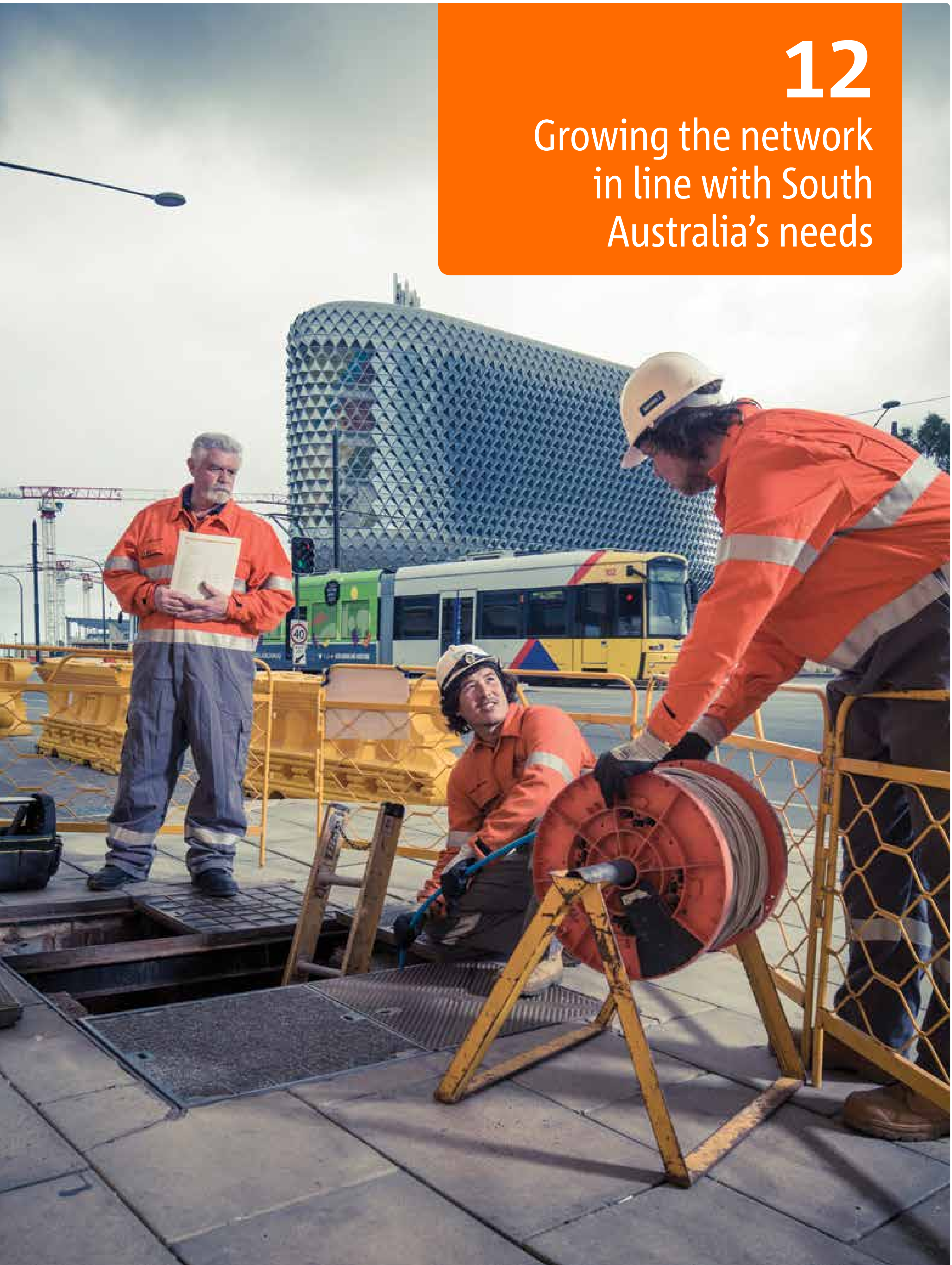
11.5

Benefits to customers

These proposals will provide the following benefits to South Australian customers:

- compliance with regulated obligations;
- integrated support for South Australian Government and community bushfire safety strategies (ie CFS Bushfire Safer Places);
- alignment with recent changes to Australian good electricity industry practice (following interstate bushfire disasters);
- prudent and efficient management of overall safety risk levels;
- treatment of specific safety risks to the community and our workforce;
- more effective and timely communications on community safety around power lines (eg 'Look Up and Live');
- alignment with specific customer preferences as revealed in Willingness to Pay discrete choice modelling; and
- alignment with customer expectations as revealed in our Customer Engagement Program.

12
Growing the network in line with South Australia's needs



12

Key points

- We invest in the distribution network to supply electricity which meets South Australia's community, demographic and commercial needs.
- Network capacity must be capable of meeting peak demand requirements from customers (largely driven by air conditioning loads in summer), whenever and wherever they occur.
- The Australian Energy Market Operator has forecast that the overall (system-level) trend in demand will be flat.
- We build the network to meet local area demands which are impacted by a complex range of factors including pockets of regional growth, urban infill developments, more single person households as the population ages, installation of solar panels and customers' response to energy efficiency.
- In the 2015–20 RCP, we propose to continue to enhance localised peak demand forecasting methods, approaches and stakeholder engagement to ensure network capacity investment meets customer needs at the right time and the right place, and continue to connect customers efficiently and promptly.

12.1

Our regulated obligations

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 consumers with respect to the price, quality, safety, reliability and security of electricity supply (ie the primary focus of the national electricity objective or **NEO**) there are a number of specific regulatory obligations which SA Power Networks is required to meet in 'growing the network in line with South Australia's needs' including:

- we must use our best endeavours to meet the following reliability and customer service targets set by ESCoSA for the 2015–20 RCP:
  - Unplanned System Average Interruption Duration Index (**USAIDI**) targets (in minutes) for the four feeder categories of: Central Business District (**CBD**), Urban, Short Rural (**SR**) and Long Rural (**LR**). These will be based on the average of five years' historical performance excluding Major Event Days (**MEDs**); and
  - Unplanned System Average Interruption Frequency Index (**USAIFI**) targets (number of interruptions) for the same four feeder categories. Again, these will be based on the average of five years' historical performance excluding MEDs;
- in addition, SA Power Networks will be required to report USAIDI and USAIFI annually for seven geographic areas — Adelaide Business Area (same as CBD), Major Metropolitan Areas, Barossa/Mid-North/Riverland/Murraylands, Eastern Hills/Fleurieu Peninsula, Upper North and Eyre Peninsula, Kangaroo Island and the South East;
- we must meet or manage the expected demand for Standard Control Services;
- each year we must produce a Distribution Annual Planning Report (**DAPR**) in accordance with the requirements of Section 5.13.2 of the National Electricity Rules (**NER**). The information contained within the DAPR must comply with the requirements of Schedule 5.8 of the NER and describes:
  - our network;
  - planning procedures and policies;
  - a summary of network reliability for the previous financial year;
  - forecast loads and emerging system limitations;
  - proposed solutions to those system limitations; and
  - major construction activities that we have completed or committed to in the last 12 months;
- when we invest in network infrastructure in order to provide a safe and reliable supply of electricity we must apply the AER's Regulatory Investment Test — Distribution (**RIT-D**) when assessing the economic efficiency of different investment options, including non-network solutions to network constraints. The RIT-D establishes clearly defined and efficient processes for distribution network investment in the National Electricity Market (**NEM**) addressing a range of needs, including:
  - the replacement and renewal of ageing and deteriorating assets;
  - changing consumer energy usage patterns that drive increased peak demand for power; and
  - government standards for reliable electricity services.

  The RIT-D is a cost-benefit test that electricity distribution network businesses must apply; and
- from 1 July 2015 SA Power Networks must update its Connection Policy to comply with Section 6.7A.1 of the NER by adopting the Connection Charge Principles outlined in Section 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 Policy must specify who may be required to pay a connection charge, the circumstances when a charge may be imposed and the aspects of a connection service for which a charge may be imposed.

12.2

Key issues in 'growing the network in line with South Australia's needs'

As South Australia grows and develops, the electricity distribution network also grows. Growth can come from existing customers who increase their demands on the network, or from customers who need new or upgraded connections, which can include extension of power lines to their properties and businesses.

SA Power Networks is obligated to plan, build and operate the network so that supply and connections are available for customers where and when they need them. This task is challenging at the best of times. But today, with change and uncertainty in so many areas that affect the balance of network demand and supply, the challenge is greater than ever.

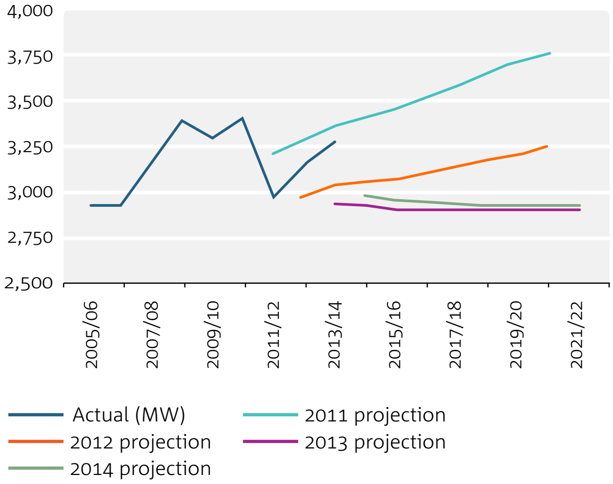
The key areas of focus in 'growing the network in line with South Australia's needs' are:

1. sales and demand forecasting at the distribution system level (ie at a 'global' level);
2. meeting local network capacity needs; and
3. connecting customers.

12.2.1
Sales and demand forecasting at the distribution system level

The Australian Energy Market Operator (**AEMO**) operates the national wholesale market and provides peak demand forecasts for the NEM. Each year AEMO produces forecasts of peak demand (maximum amount of electricity consumed at a point in time) and energy consumed in total over the year for each jurisdiction. Forecasting sales and peak demand is an imprecise science largely due to the diverse impacts of policy, technology and consumer behaviour. AEMO continues to seek to enhance its forecasting methods and has repeatedly modified its forecasts since 2011 to better signal current and future energy patterns (see Figure 12.1).

Figure 12.1: AEMO peak demand projections for South Australia to 2021/22 (MW)



SOURCE: SA POWER NETWORKS' ANALYSIS OF AEMO DATA 2014

In South Australia, the usual high summer temperatures lead to extra-ordinary demand for air cooling. More than 90% of South Australian households have air conditioning which places significant demand on the network. In the few extremely hot days of a South Australian summer, typically around six to nine days each year, air conditioning loads cause South Australia's electricity demand to double relative to average demand levels on mild days. As a consequence, our State has the 'peakiest' demand in Australia and SA Power Networks is required to build infrastructure to meet the peak demand that occurs for less than 2% of the year.

In recent years, South Australia has not experienced the expected growth in peak demand and has prudently deferred investment in building capacity in the network. A number of factors have had a varying influence on the level of State-wide peak demand and energy consumption. These include:

- milder weather patterns in 2010 and 2011;
- customer response to rising cost of living costs, including energy costs;
- the improved energy efficiency of appliances;
- the local generation of electricity (solar PV panels) and the level of energy produced which is used in-house; and
- general economic conditions.

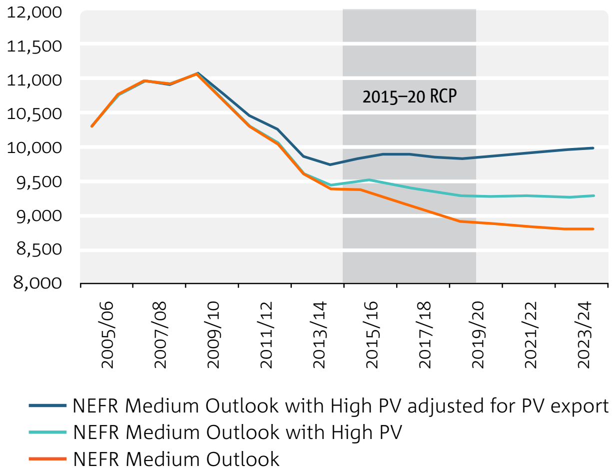
AEMO demand and energy forecasts

While AEMO forecasts energy consumed on a whole of state basis it does so at the Transmission Network Connection Points level. To translate AEMO forecasts into sales by SA Power Networks, several adjustments to AEMO's 10% Probability of Exceedance (**PoE**) forecasts (medium growth outlook) are required. These include adjustments:

- to reduce the AEMO forecast by the amount of distribution losses;
- to utilise the high future growth case for solar PV as it more closely matches the level of solar PV approval seen since the PV Feed-in Tariff (**FiT**) schemes closed; and
- to add back the level of solar energy exported to the grid (as AEMO forecasts assume all solar energy is used in house) and to match the PV output to the peak time our network currently experiences.

On this basis the outlook for SA Power Networks' energy sales is for zero growth to 2020. Figure 12.2 shows AEMO's National Energy Forecast Report[38] (**NEFR**) sales for the Commercial and Residential segment with their medium solar PV forecast, with their high PV forecast and with the high PV forecast adjusted for PV export (the surrogate for SA Power Networks' sales excluding the Major Business segment).

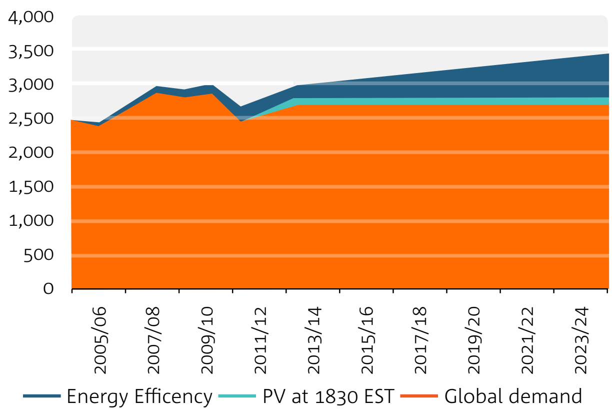
Figure 12.2: AEMO NEFR forecasts for residential and commercial energy (GWh)



SOURCE: SA POWER NETWORKS' ANALYSIS OF AEMO DATA 2014

AEMO's forecasts for both energy and demand use the same assumptions. Figure 12.3 shows the AEMO forecast for Residential and Commercial demand (substituting the high case solar PV forecast for the medium case). Figure 12.3 shows that the demand at 18.30 EST would be growing in future years, but energy efficiency and, to a lesser extent, the PV output at 1830 results in a forecast level of demand at the same level as in 2013/14. That is, the global demand growth at 1830 EST will essentially be 0%. Note that the PV output at 1830 is very low, as output is only 7% of possible output due to the lower level of solar irradiation at 1830 EST. It is interesting to note that in three of the last six years AEMO's forecasts for 10% PoE outcomes were exceeded (in January 2009, January 2011 and January 2014). The forecasts are 10% PoE, with the frequent exceedance due to severe weather.

Figure 12.3: AEMO forecasts for Residential and Commercial 10% PoE demand — medium growth, high case PV scenario (MW)



SOURCE: SA POWER NETWORKS' ANALYSIS OF AEMO DATA 2014

38 AEMO National Electricity Forecasting Report, aemo.com.au

Recent demand growth has slowed from the rapid growth seen in the period 2004/05 through 2010/11 because of several factors, including:

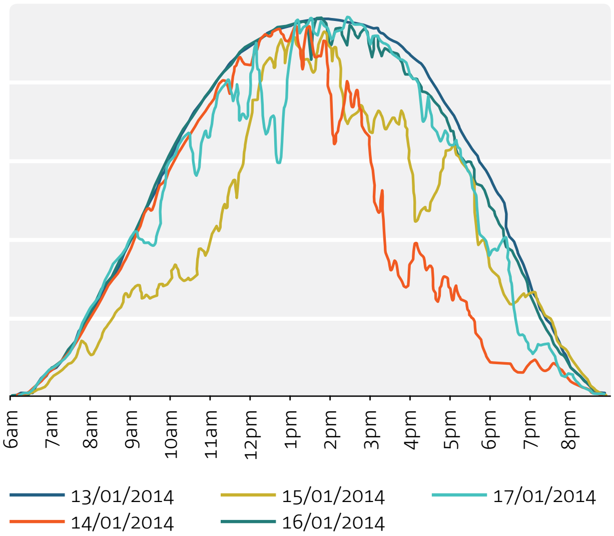
- less economic growth, reflecting the impact of the global financial crisis combined with the loss of manufacturing jobs with the high Australian dollar;
- more energy efficient appliances being used at peak times, including more efficient air-conditioners being installed, often replacing older inefficient ones that required more capacity; and
- high PV installation, which has shifted the peak from 5pm local time to a lower level of demand at 7 pm local time.

Solar PV offsets some peak demand, but only when it is sunny

South Australia has the highest penetration of domestic rooftop solar PV panels of all NEM regions. By offsetting consumption in customers' premises, solar PV installations reduce network demand to some degree — but only up until late afternoon, and not reliably when there is cloud cover. As shown by the orange line in Figure 12.4 solar output is very susceptible to cloud cover, which occurred on the afternoon of 14 January 2014.

Despite reducing network demand when sunny, the high solar PV penetration actually exacerbates the peakiness of the South Australian electricity system. Once solar PV output falls late in the day, peak demand returns to high levels. Therefore capacity to meet peak demands must still be provided, albeit for even shorter periods.

Figure 12.4: Solar PV output during 5-day heatwave, January 13–15 2014



SOURCE: SA POWER NETWORKS 2014

Total sales forecast including Major Business Customers

AEMO's forecast is for energy sourced from the NEM and not for customer sales, hence the slight amendment for distribution losses and for the export of PV output back to the grid. AEMO does not disclose a major customer forecast, so an SA Power Networks forecast has been used to include the major business sales volumes. Table 12.1 outlines SA Power Networks' total sales forecast.

Table 12.1 SA Power Networks' sales forecast 2015–20 RCP

GWh pa	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
Customer Sales	9,303	9,412	9,445	9,432	9,412	9,395
Major Business	1,115	1,098	1,085	1,035	1,035	1,035
Total Sales	10,418	10,510	10,530	10,467	10,447	10,430
% Growth pa						
Customer Sales		1.2%	0.4%	-0.1%	-0.2%	-0.2%
Major Business		-1.5%	-1.2%	-4.6%	0.0%	0.0%
Total Sales		**0.9%**	**0.2%**	**-0.6%**	**-0.2%**	**-0.2%**

SOURCE: SA POWER NETWORKS 2014

12.2.2 Meeting local network capacity needs

In developing SA Power Networks' demand forecasts, it is the growth and relative 'peakiness' of the loads in specific regions and local areas that must be accommodated by the capacity of the network.

This is referred to as the spatial demand forecast and is the forecast that underpins SA Power Networks' capital expenditure projections with regard to network capacity.

The SA Power Networks demand forecast is reviewed annually after each summer peak load period, with the last review completed in the second quarter of 2014. This review considered the impact of any new peak load recordings following the 2013/14 Summer, system modifications and new large load developments, in accordance with SA Power Networks' network forecasting procedures.

While 'global' (ie total aggregated) demand has moderated in recent years, network 'spatial' demands have varied in many areas due to localised economic and demographic changes including:

- in recent years, demand has decreased at some locations where, for example, manufacturing closures may have occurred;
- parts of the Adelaide CBD have grown considerably, as have some urban rural centres such as Port Lincoln on the Eyre Peninsula where there has been continued growth in the aquaculture and fisheries industry;

- many regional centres close to Adelaide are also experiencing a rebirth in their economies as retiring baby-boomers seek a 'sea-change' or 'tree-change' and families look for more affordable housing in semi-rural or coastal locations. So, as sizeable portions of the population change their minds about where and how they want to live, housing developments, suburbs and retirement villages are being developed in diverse locations, driving local network upgrades; and
- the number of single person households continues to increase due to an ageing population and other demographic trends, while urban planning continues to promote higher density urban living. Demand for such housing and the redevelopment of older housing stock (ie 'infill' development) are forecast to continue in the 2015–20 RCP.

SA Power Networks must respond to these localised demand increases wherever and whenever they occur.

Planning Process

The Distribution Annual Planning Report (**DAPR**) is SA Power Networks' assessment of its distribution system's capacity to meet forecasted demand over the eleven years from 2015/16 to 2025/2026 and possible plans for augmentation of the distribution network. As described in Section 7.3, the DAPR mirrors our Distribution System Planning Report, the internal document that provides the source data for the publicly available DAPR. A flow chart detailing the decision making process followed by SA Power Networks in planning and augmenting the distribution network is shown in SA Power Networks' Expenditure Forecasting Methodology in Attachment 7.5 of the Proposal.

The DAPR includes an overview of SA Power Networks' system planning methodology, 15 regional development plans covering SA Power Networks' connection points, sub-transmission lines, zone substations, distribution feeder exits and the low voltage network. Where relevant, details of system constraints and the proposed corresponding projects are included within these development plans.

For forecast capacity constraints that would require more significant network investment, it is now standard practice to examine whether cost effective 'non-network' options may be available using a combination of:

- best practice internal planning principles as detailed in SA Power Networks' DAPR; and
- applying the AER's RIT-D (for projects meeting the RIT-D minimum criteria) to establish clearly defined and efficient processes for distribution network investment.

The DAPR is available for viewing on **TalkingPower.com.au**, and the AER's RIT-D Guideline can be seen **aer.gov.au/node/19146**.

Over the current RCP (2010–15) we have seen a moderation in capacity expenditure. Going forward we forecast a stabilisation and overall flattening of our capacity work program across South Australia necessary to serve the changing economic, demographic and lifestyle needs of the community.

12.2.3 Connecting customers

Connecting customers efficiently and economically is an important part of our business and a crucial service for our residential and business customers and in supporting South Australian economic growth.

Most years, SA Power Networks creates or modifies about 24,000 customer connections to the network, for residential, commercial and industrial purposes. The vast majority (about 23,000) are classified as 'basic connection services, for predominantly individual residential and small commercial customers. The remaining 1,000 are 'negotiated connection works' with two thirds being large commercial and industrial developments and one third relating to industrial or residential subdivision developments.

With the significant take up of solar PV panels, we have in recent years provided more than 30,000 meter change-overs (import/export meters) for these installations per annum.

The factors that influence forecasts of the number of connections to the distribution network include:

- population growth and movement;
- economic conditions;
- upgrade of connections for major loads such as:
  - continued increased use of air conditioning; and
  - future use of electric vehicles;
- the increased amount of local generation and storage that connects to our network; and
- infill housing.

Outlook for SA Power Networks' customer connections expenditure forecasts to 2019/20

According to the Australian Bureau of Statistics, the population of South Australia is projected to increase by 22.7% over the next 25 years. Growth will be concentrated in the Adelaide metropolitan area, with 27.6% growth, and around 11.4% in regional centres of the State.

Customer connection expenditure is associated with additions, upgrades or alterations resulting from the requirements of specific customers. This expenditure is divided into a number of categories, being:

- **Minor Customer Connections (costing less than $30,000)** — connections generally associated with new houses or additions and alterations to existing houses;
- **Underground Residential Developments** — connections to the existing distribution network of new housing developments and rebates — payments to customers for assets which have been gifted to SA Power Networks;
- **Medium Customer Connections (costing between $30,000 and $100,000)** — connections generally associated with non-residential buildings, for example businesses and 'other' dwellings, such as flats; and
- **Major Customer Connections (costing more than $100,000)** — connections generally associated with large business investment, for example, defence, mining, major non-residential buildings, shopping centres and intensive agriculture, and government and private infrastructure investment, for example, schools, railways and water supply. SA Power Networks receives funding directly from some customers towards their connection, in accordance with our Connection Policy.

The Customer Contributions total also includes rebates, which are payments to customers for assets which have been gifted to SA Power Networks.

We engaged consultants BIS Shrapnel to forecast the likely customer growth and associated connections for the 2015–20 RCP, see Attachment 12.5. This work has shown a small uplift in customer connections arising from:
- continued new housing development;
- infill housing;
- agricultural developments or mining; and
- general demand growth.

SA Power Networks' new Connection Policy is consistent with the requirements under the NECF and with the NECF changes from July 2015 there is expected to be more volatility in customer connection rebates, although overall the level of customer contributions towards connection expenses will be consistent with the current RCP. SA Power Networks' proposed Connection Policy for the 2015–20 RCP is submitted at Attachment 12.1.

12.3

What our stakeholders and customers have said to us, and our response

12.3.1 Understanding our customers' concerns

During the Research Phase of our TalkingPower engagement program we provided some relevant information on key topics and asked our customers and key stakeholders what they expected from SA Power Networks over the next five years and beyond. This was done in the context that any investments and operating costs would be managed within no more than a CPI increase in their network charges. Specifically, with respect to 'growing the network in line with South Australia's needs', our TalkingPower program confirmed that SA Power Networks should continue investing in network reinforcement and capacity increases to encourage future economic growth in the State.

12.3.2 Integrating customer feedback into our business planning process

These customer insights were fed into our planning for the next RCP and a range of key investment options were communicated back to customers and stakeholders for confirmation and comment. These investment priorities were then more broadly consulted on in our 'Directions and Priorities 2015 to 2020' consultation document. The investments included:
- invest efficiently by aligning our plans with industry and demographic needs;
- maintain close connections with stakeholders to ensure that the implications for planned infrastructure developments are understood;
- connect customers efficiently in line with our regulatory obligations; and
- reinforce our network to manage the impact of urban infill.

12.3.3 Feedback received on our Directions and Priorities 2015 to 2020 consultation document

Responses to the 'Directions and Priorities 2015 to 2020' consultation document with respect to 'growing the network in line with South Australia's needs' were:

Business SA Submission:
- "We recognise that forecast price rises for electricity distribution should remain under CPI for the next four years and this is welcomed by Business SA. However, South Australian businesses still face the highest electricity costs in the country and if SAPN wants to support economic growth in this State, it can play a pivotal role through finding efficiencies within its forecast operating and capital expenditure across the next regulatory period from 2015 to 2020."
- "We are encouraged that SAPN acknowledges its place in supporting economic growth and remind SAPN that the most effective role it can play is by reducing price pressure of network distribution charges on business, particularly small business."
- "Essential service providers such as SAPN can facilitate that growth by distributing electricity at the lowest possible cost. SAPN will benefit from the growth of the South Australian economy, but this growth will only occur if both Governments and essential service providers work to bring down the costs of doing business in South Australia."

12.4

SA Power Networks' response to consultation, and proposed expenditures

We have considered the feedback from customers and stakeholders regarding our connection process and priorities and how the distribution network will be used in the future.

Throughout our Customer Engagement Program customers and stakeholders responses have consistently supported our investments program in regard to 'growing the network in line with South Australia's needs' by continuing to invest in network reinforcement and capacity increases to encourage future economic growth in the State.

We note Business SA's support for developing the network to support economic growth and their view of the impact of price rises on such growth. While we have obligations to connect customers where and when they wish we have sought to address the price impact issue within the context of the overall Proposal. This matter is further discussed in Chapter 17 on the service-price trade-off.

For the 2015–20 RCP our proposed program of expenditures for 'growing the network in line with South Australia's needs' are focused on four key project areas:

1. **Invest efficiently by aligning our plans with industry and demographic needs** by closely monitoring the needs and expectations of our customers and cost drivers for network investment to continue 'growing the network in line with South Australia's needs' while ensuring our strategic plans take into account the emerging changes to how customers use the network;
2. **Continue to maintain our already close connections** with South Australian business, government and regulatory stakeholders to ensure that infrastructure implications for impending developments are understood and planned for, and continuously improve these processes over time;
3. **Reinforce our network through augmentation and capacity projects** to meet or manage the expected demand for Standard Control Services (**SCS**) as a result of necessary upgrades to our network from changes to the Electricity Transmission Code (**ETC**) or as an output of our planning processes (eg transmission connection point substations, sub-transmission lines, new and augmented substations and new and augmented distribution and low voltage lines); and
4. **Connect customers efficiently in line with our regulatory obligations** — customer connection-driven expenditure is associated with additions, upgrades or alterations to our network as a result of the requirements of specific customers.

Table 12.2 outlines the key capital expenditures proposed for the 2015–20 RCP expressed in June 2015 dolllars, and Table 12.3 details changes to operating costs above the efficient base year. Further detail on specific capital and operating items can be found in the referenced sections of this Proposal.

Table 12.2: growing the network in line with South Australia's needs' — capital expenditures

Item	2015–20 RCP 2015$	Reference section
ETC network reinforcement	14.1	20.6.1
Strategic reinforcement (incl. land)	41.6	20.6.1
Demand driven reinforcement	194.1	20.6.1
Customer connections (net)	189.4	20.7.4
Capex Total	**$439.2m**	

Table 12.3 — 'growing the network in line with South Australia's needs' — operating step changes expenditure

Item	2015–20 RCP 2015$	Reference section
NECF customer charging changes — resources	1.3	21.6.1
Opex Total	**$1.3m**	

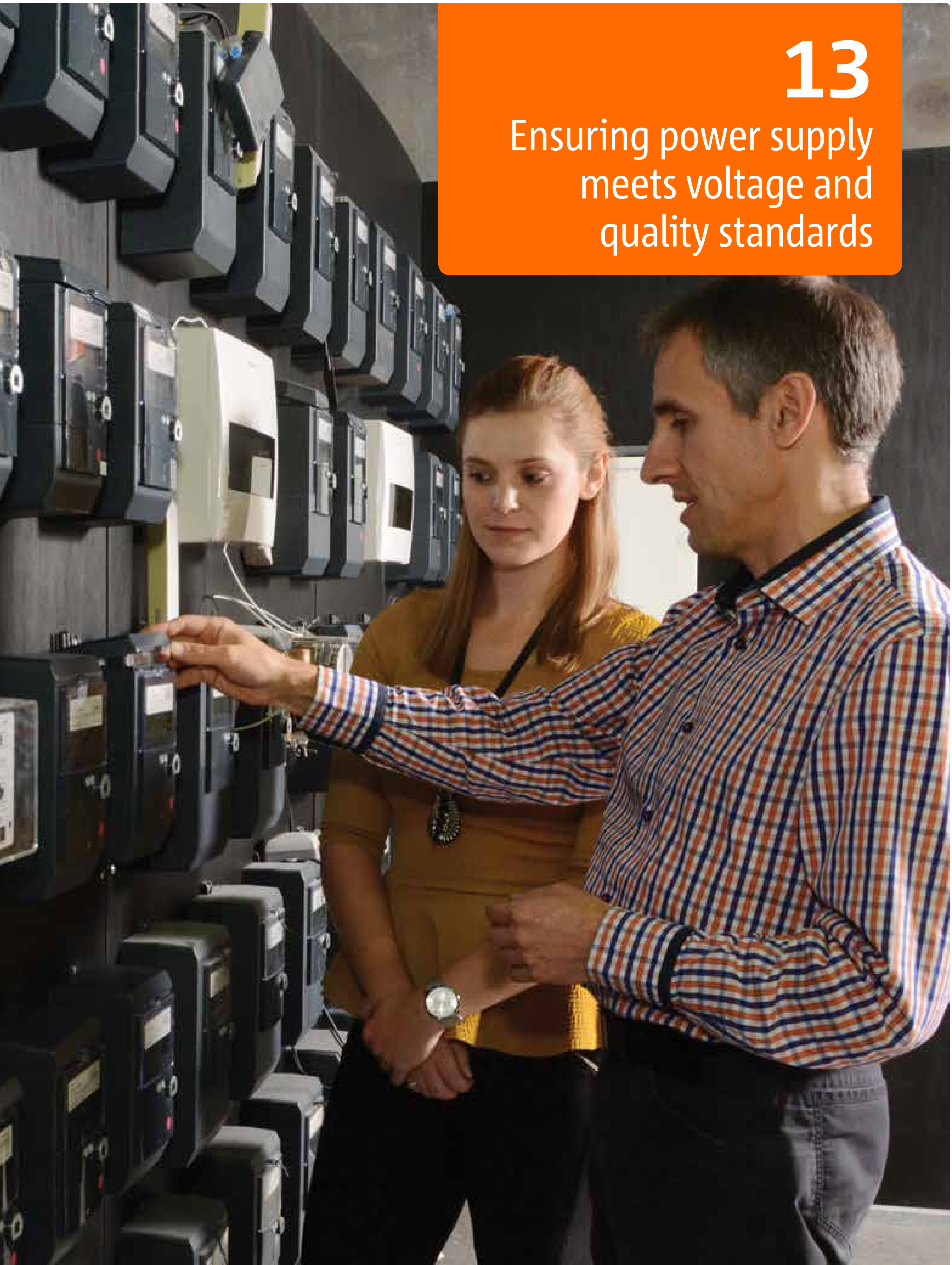
12.5

Benefits to customers

These proposals will provide the following benefits to South Australian customers:

- compliance with regulated obligations;
- timely provision of network capacity in line with customers' needs;
- timely new, upgraded or altered connections for customers;
- a more adaptable network that can accommodate customers' changing preferences for non-network solutions and distributed energy resources (**DER**); and
- alignment with customer expectations as revealed in our Customer Engagement Program.

13 Ensuring power supply meets voltage and quality standards



13

Key points

- Power quality relates to the regulated physical characteristics of power supplied to customers, including voltage, generally at the low voltage (**LV**) level of the network (ie mains 230V).
- Historically, power quality problems arose from large air conditioners or other large loads affecting local power quality (eg lights dimming due to low voltage). More recently, solar photo-voltaic (**PV**) generation is creating new problems in managing energy voltage.
- Currently there is limited monitoring of the existing LV network, with reliance placed on customers raising issues with SA Power Networks.
- We are seeing the start of the 'two-way network', where energy flows are complex and dynamic. Left unmanaged, customers will face escalating power quality issues over time.
- In the 2015–20 RCP, we propose to improve monitoring of the LV network to allow for pro-active management of power quality issues, ensure the network can accommodate connection of more Distributed Energy Resources (**DERs**) (eg solar PV and other renewable technologies) and cost effectively address local quality and reliability issues in poorly-performing areas of the network.

13.1

Our regulated obligations

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 consumers with respect to the price, quality, safety, reliability and security of electricity supply (ie the primary focus of the national electricity objective or **NEO**) there are a number of specific regulatory obligations contained in the South Australian Electricity (General) Regulations and ESCoSA's Electricity Distribution Code (**EDC**) in relation to 'ensuring power supply meets voltage and quality standards'.

These requirements impose obligations on SA Power Networks to design, install, operate and maintain the network so that the voltage characteristics meet relevant Australian Standards. In particular we must:

- maintain the voltage level at a customer's supply address within specified tolerances;
- contain voltage fluctuations within specified limits; and
- ensure any harmonic voltage distortions do not exceed specified values.

13.2

The key areas of focus in 'ensuring power supply meets voltage and quality standards' are:

1. voltage level issues;
2. solar PV and other generation creates problems in managing voltage;
3. enabling the emerging two-way network; and
4. managing the low voltage network.

Key issues in 'ensuring power supply meets voltage and quality standards'

13.2.1 Voltage level issues

Historically, customer appliances and equipment were reasonably tolerant to fluctuations in the electricity supply voltage. However, the advent of the digital age from the 1980s onwards saw customers increasingly adopt more sophisticated computerised equipment and control systems. These customer loads are more sensitive to the quality of electricity supply. Voltage fluctuations or voltage levels outside tolerance can result in damage to customer equipment and/or repeated disconnection of customer loads.

Power quality issues are often caused by the varying nature of customer electricity demand (and more recently, customer embedded generation). The majority of customers are connected to the LV network (only a small number of industrial and commercial customers connect directly to the high voltage (**HV**) network), so quality of supply issues tends to be more prevalent in the LV network. As the underlying causes of power quality issues are often intermittent or transient in nature, extensive investigation and analysis to identify and remedy the problems is required.

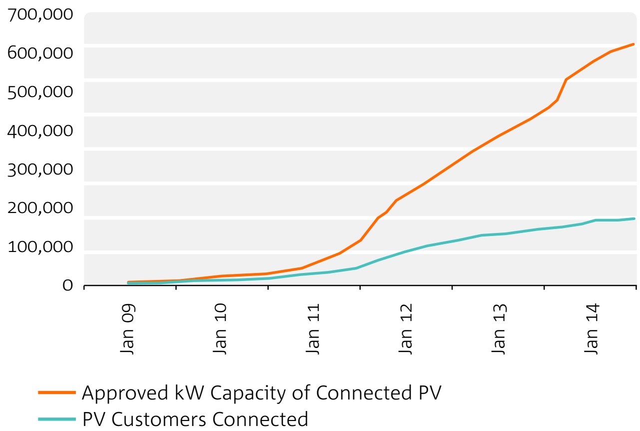
Low voltage problems often occur at the extremities of the LV network when actual electricity demands exceed the design loads for those parts of the network. In recent years, a significant increase in air-conditioning use has been a key driver of these voltage issues.

Since 2010 SA Power Networks has experienced a significant increase in solar PV generation, on the LV network. This is creating an increasing number of high voltage problems in areas of our LV network which are reflected in a significant increase in quality of supply related customer voltage enquiries.

13.2.2 Solar PV generation creates problems in managing voltage

Figure 13.1 below illustrates the rapid increase in solar PV generation connected to SA Power Networks' distribution network. 24% of customers in South Australia now have solar PV installed at their premises, with a combined generating capacity of over 500MW, or nearly 15% of the State's peak demand.

Figure 13.1: Solar PV connections to SA Power Networks' distribution network.



SOURCE: SA POWER NETWORKS ANALYSIS 2014

The peak output of solar PV into the network typically occurs in the middle of the day when many residential customers are at work and in-house electricity consumption is low. Due to the large penetration of solar PV, a number of suburbs are now net electricity generators rather than net consumers at this time. A surplus of electricity generated into the LV network at these times causes voltage levels to rise.

As well as impacting surrounding customers, the effects of high voltage can affect the solar PV customers causing the voltage increase — the customer's solar PV system inverter may recognise that pre-set network voltage limits have been reached and will disconnect the panels from the network. This prevents the customer from exporting energy to the grid until the voltage returns to normal levels.

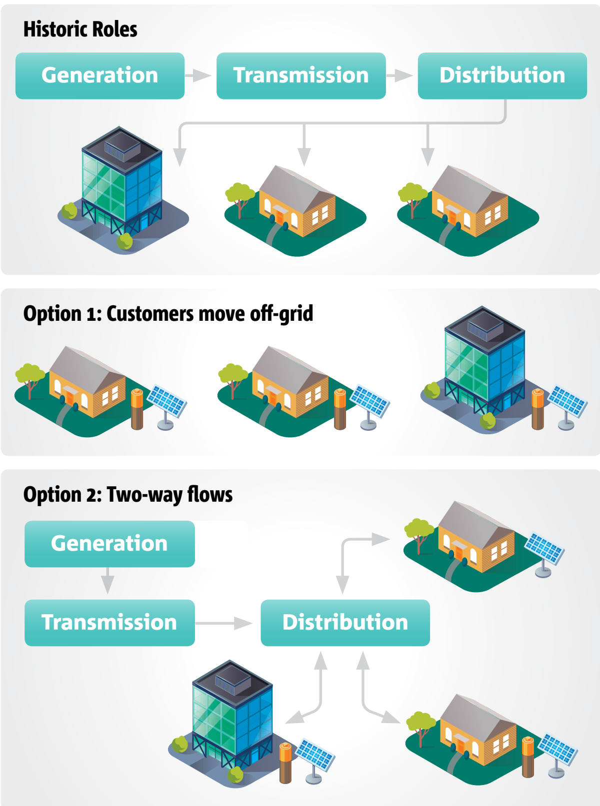
Modelling and analysis[39] of SA Power Networks' network indicates that on many LV feeders in both overhead and underground networks, voltage regulation requirements limit acceptable PV penetration to around 25% of customers. This level is already exceeded in many areas of the network.

As more solar PV systems are connected to the LV network, we expect more supply quality issues to arise.

13.2.3
Enabling the emerging two-way network

Until recently, the network operated on a one-way flow of energy from centralised generation to customers. As noted in Section 13.2.2, we are now seeing that in some suburbs at times of full sunshine and low localised consumption, electricity flows back into the wider grid. The need to manage these more complex variable two-way power flows and the resulting localised swings requires us to transform our existing distribution system into a 'two-way network'. This will allow the effective use of existing solar generation, to enable the connection of any additional generation that customers choose to install and to ensure the network is capable of dealing with new customer technologies such as electric vehicles and battery storage.

Figure 13.2: The emerging two-way network



We expect greater penetration of these new technologies over the next five years and without the necessary investment in the network we will see escalating power quality issues occurring.

Given the increasing complexity of these energy flows, we need to increase the level of monitoring and control equipment integrated with the LV network.

13.2.4
Managing the low voltage network

As power quality issues are often caused by customers, we can impose obligations on customers to ensure their installations meet relevant Australian Standards and other parameters. This helps alleviate, but not eliminate, power quality issues on the LV network.

With over 30,000 km of LV network across South Australia, to date widespread pro-active power quality monitoring by SA Power Networks has not been cost-effective. Currently SA Power Networks undertakes limited and targeted monitoring at the distribution transformer level using manually read power quality data loggers.

We also heavily rely on customer reports of poor supply quality as the trigger for an investigation into a problem. These 'reactive' investigations only provide a snapshot of power quality data for a small part of the LV network and over a limited timeframe. With the increasing complexity of power flows over the LV network, reactive approaches to power quality are not sustainable.

Emerging technological developments are creating not only alternative power supply options for customers but opportunities for SA Power Networks to cost-effectively and pro-actively monitor and manage more of the network. These emerging technologies include:

- 'smarter' switches (which can be operated remotely or automatically to re-route power supplies);
- cheaper permanent LV monitoring (with telecommunication) solutions located at strategic areas in the LV network;
- 'smart' meters (which can be utilised by the network to provide real time load and voltage data);
- battery storage (which could be utilised to supply energy to areas regularly impacted by upstream outages and operate as a micro-grid during these events); and
- equipment with remote management capabilities (which could provide more flexible options to manage network load and generation requirements).

As discussed in Section 13.2.3 new customer-side technologies are increasing the complexity of managing the network and heighten the need for better control and monitoring. The advent of these technologies including smart meter technology afford a cost-effective opportunity for SA Power Networks to prudently increase pro-active monitoring of power supply quality across the LV network.

39 SA Power Networks Consultancy Services for impact of Distributed Energy Resources on Quality of Supply, PSC, May 2014

13.3

What our stakeholders and customers have said to us, and our response

13.3.1
Understanding our customers concerns

During the Research stage of our TalkingPower consultation program we provided relevant information to customers and key stakeholders and asked what they expected from SA Power Networks over the next five years and beyond. This was done in the context that any investments and operating costs would be managed within no more than a CPI increase in their network charges. Specifically, in relation to 'ensuring power supply meets voltage and quality standards', the program confirmed that:

- customers are consuming less energy in response to rising electricity retail prices and they are investing in local solar PV generation, accelerated by government incentives;
- customers are changing the way they use the network with their continued uptake of solar PV and other embedded generation, and this will require us to adapt the network accordingly; and
- customers were initially unaware that the network had to be upgraded to enable embedded generation to feed-in energy to the distribution network. Customers supported upgrading the distribution network to enable two-way network flows to allow take-up of more DERs.

13.3.2
Integrating customer feedback into our business planning process

These customer insights were fed into our planning for the next RCP and a range of key investment options were communicated back to customers and stakeholders for confirmation and comment. These investment priorities were then more broadly consulted on in our 'Directions and Priorities 2015 to 2020' consultation document.

The investments included:

- proactively and selectively monitor the LV network to more accurately plan low voltage capacity upgrades in a world of rapidly evolving technology;
- improve our knowledge and support customer take-up of DER such as micro-generation, energy storage and electric vehicles;
- address quality of supply issues in the worst performing areas of the network; and
- enable a two-way network through strategic monitoring and prepare the network to support additional embedded generation and customer equipment.

13.3.3
Feedback received on our Directions and Priorities 2015 to 2020 consultation document

Responses to the 'Directions and Priorities 2015 to 2020' consultation document with respect to 'ensuring power supply meets voltage and quality standards' were:

Business SA submission:

- "We recognise that the significant increase in solar PV generation has caused some issues for SAPN in managing the low voltage (LV) network, particularly in specific localised areas."
- "We note that SAPN plans to selectively monitor the LV network and that this would include the installation of voltage monitoring devices at a transformer level. While accepting that it will take some time to roll out smart meters in South Australia, Business SA acknowledges that a broad roll out of smart meters should enable SAPN to monitor voltage at an end user level."
- "We accept that this may require the State Government to amend its proposed New and Replacement Policy for smart meters and consequently we encourage SAPN to work with the State Government to find a solution."

13.4

SA Power Networks' response to consultation, and proposed expenditures

Our Proposals for 2015–20 remain consistent with the proposed directions outlined in our 'Directions and Priorities 2015 to 2020' consultation document.

Pro-active management and monitoring of the LV network will provide better information about how our customers are using the network, enabling us to plan and upgrade the network in response to customer and technological change. More automated controls over network voltage levels are also needed to increase the network's flexibility in adapting to customer-side technologies and to facilitate two-way energy flows on our network. Business SA's response to the Directions and Priorities consultation recognised this need and further identified the benefits for managing a two way network that can be derived from the installation of advanced metering in homes and businesses.

SA Power Networks has developed a 'Smarter Network Strategy' that sets out a coordinated approach to integrating intelligent equipment and systems into the network to manage risk, optimise asset investment, manage reliability and enable the two-way network to maximise customer value. To improve LV network management, it is proposed to consider the whole supply chain from the zone substation to the LV feeder supply transformer through to the customer's meter.

SA Power Networks has already laid important foundations to deliver on this strategy. We commenced the implementation of a project in 2012 to deploy a new Supervisory Control and Data Acquisition (**SCADA**) system and an Advanced Distribution Management System (**ADMS**). These systems provide the 'backbone' system capability to allow remote monitoring, operation and control of the electricity network. The ADMS, which will be operational by 2015, will be the technological platform to be utilised for future smarter network capabilities across the business.

The key initiatives to 'ensuring power supply meets voltage and quality standards' in the next RCP are:

Improve voltage regulation by:
- using existing SCADA facilities to remotely control substation output voltage at 20 metropolitan substations and on 85 feeders with solar penetration greater than 20%;
- installing HV regulation with SCADA to 10 country substations where it is not prudent or cost efficient to install full substation SCADA; and
- retrofitting SCADA to 63 HV line voltage regulators.

Improve transformer monitoring by:
- Installing transformer monitors and using 3G telecommunications to remotely collect transformer load and voltage information as follows:
  - country monitoring: 740 single wire earth return (**SWER**) transformers, 460 feeders, 65 non SCADA substations; and
  - metropolitan monitoring: 635 selected pad-mount transformers, 85 feeders.
- utilise remotely read customer metering for quality of supply monitoring by:
  - leveraging off our advanced metering Proposal (discussed further in the next chapter) and installing
  - approximately 10,000 telecommunications modules per annum on new and replacement meters in targeted locations.[40]

Installation of this equipment and associated systems will enhance customer service, reduce customer voltage complaints and better facilitate a two-way power flow on the distribution network. Our systems will be modified to integrate our ADMS and work management systems to enable the timely planning and delivery of work and the ability to provide customer feedback.

Table 13.1 outlines the key capital expenditures proposed for the 2015–20 RCP. Further detail on specific capital items can be found in the referenced sections of this Proposal.

Table 13.1: 'Ensuring power supply meet voltage and quality standards' — capital expenditures

Item	2015–20 RCP 2015$	Reference section
Voltage Regulation and Monitoring	107.4	20.6.1, 20.6.3
Flexible Load Management	4.3	20.6.1
Capex Total	**$111.7m**	

40 Undertaken during regular meter replacement work in LV areas with high customer numbers, not supplied by new underground cable (where power quality issues are not expected), selecting 3-phase meters where possible.

Table 13.2: 'Ensuring power supply meet voltage and quality standards' — operating step changes expenditure

Item	2015–20 RCP 2015$	Reference section
Flexible Load Management	1.0	21.6.2
Opex Total	**$1.0m**	

13.5

Benefits to customers

These Proposals will provide the following benefits to South Australian customers:
- compliance with regulated obligations;
- maintenance of customer quality of supply;
- improved timeliness and optimisation of future network upgrades;
- enhanced customer service capability with regard to enquiries on quality of supply;
- helping to enable a more adaptable network that can accommodate customers' changing preferences for DER;
- enhanced capability to understand and deal with DER issues as we move towards a two-way network with increased Demand Side Participation (**DSP**); and
- alignment with customer expectations as revealed in our Customer Engagement Program.

14 Serving customers now and in the future

14

Key points

- Customers are experiencing a level of connectivity and information access across a range of industries that is transforming their expectations of SA Power Networks; they expect greater choice and control over all of their services. Customers expect to be able to install new technologies such as solar PV and electric vehicles with a minimum of fuss; and customers expect service providers like us to support their preferences.
- High rates of technological change, customer expectations and market developments mean that customer service offerings that have been suitable in the past may not be fit for the future.
- SA Power Networks is committed to a service model that keeps the voice of the customer, and delivery on their needs, at the centre of our business.
- Our Customer Service Strategy, built on extensive research and customer engagement, represents a transformational approach to customer service in our industry.
- In the 2015–20 RCP, we propose to deliver information, service, communications and self-service options that our customers value, provide accurate and timely information on service status and power restoration activities, and provide increasing levels of advisory information in line with customers' current and future electricity needs.
- We also propose to facilitate the further connection of new technologies to advance the two-way network of the future, and introduce cost-reflective tariffs to promote efficient customer investment in such technologies and to address the increasing cross subsidies between customers. Installing more capable meters as standard for new and replacement connections will support these initiatives along with upgrading our systems and processes to manage increased volumes of customer, metering and network data.
- We will replace our network billing, metering and associated customer systems to maintain a reliable and secure service and position ourselves for changing market conditions, including proposed Australian Energy Market Commission reforms.

14.1

Our regulated obligations

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 consumers with respect to the price, quality, safety, reliability and security of electricity supply (ie the primary focus of the national electricity objective or **NEO**), the following regulatory obligations impact how we serve our customers now and in the future:

- SA Power Networks has obligations under the Service Standard Framework (**SSF**) and Electricity Distribution Code (**EDC**) to meet reliability and customer service standards and make Guaranteed Service level (**GSL**) payments when certain customer service standards are not met. Chapter 10 elaborated on these requirements;
- Chapter 13 of this Proposal outlined the obligations imposed on SA Power Networks by the South Australian Electricity (General) Regulations and the EDC in relation to quality of electricity supply;
- National Energy Retail Rules require DNSPs to provide a 24-hour telephone fault reporting service and to give four days' notice to each customer affected by a planned interruption to supply;
- section 6.18 of the NER sets out distribution pricing requirements for DNSPs when submitting Annual Pricing Proposals, including obligations with respect to tariff classes and establishing pricing principles which require DNSPs to take into account the long run marginal cost (**LRMC**) of the services delivered when setting tariffs;
- the Australian Energy Market Commission (**AEMC**) has also published significant distribution pricing Rule changes[41] proposed to strengthen the obligation for tariffs to reflect the LRMC of services delivered. These changes are expected to be finalised in November 2014;
- Chapter 7 of the NER and instruments under Chapter 7 such as the Australian Energy Market Operator's (**AEMO's**) Metrology Procedures, Market Settlements and Transfer Solutions Procedures and Business-to-Business Procedures also impose a range of obligations on retailers and DNSPs to provide timely, quality information and service to customers;
- the AER's Consumer Engagement Guideline sets out new expectations in relation to incorporating consumer views into DNSPs' future expenditure plans;
- our expenditure plans for the 2015–20 RCP also address a number of proposed changes to the NER which will be finalised in 2015 in relation to distribution pricing and metering contestability. These changes will require SA Power Networks to alter its systems and procedures to facilitate customers choosing an alternative metering provider, yet still receive the necessary meter data we need to generate network bills; and
- the South Australian Government is also developing a new policy in relation to new and replacement electricity meters which proposes that customers establishing new electricity supply connections and customers altering or replacing their supply arrangements be provided with a 'smart-ready' meter by default.

41 AEMC, Draft National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, 28 August 2014

14.2

Key issues in 'serving customers now and in the future'

Emerging technologies and market changes will create new opportunities for how customers interact with SA Power Networks and are altering their expectations of us. Services that we have offered in the past may not be suitable for the future.

SA Power Networks' key areas of focus in 'serving customers now and in the future' are:

1. adapting to changing customer expectations; and
2. promoting demand side participation by expanding cost-reflective pricing, facilitating connection of more distributed energy resources and allowing two-way network flows.

14.2.1
Adapting to changing customer expectations

Through feedback received in our TalkingPower Customer Engagement Program and the development of our Customer Service Strategy 2014–20, 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;
- they want more choice in how they interact with us;
- they increasingly value self-service technologies and access to information and services wherever they are;
- value for money retains its importance; and
- more clarity on SA Power Networks' role would be welcomed as well as greater transparency in our operations.

Customer Service Strategy

We have engaged extensively with our customers in developing our Customer Service Strategy. Our Customer Service Strategy 2014–2020 outlines a customer service vision and initiatives, providing an overview of key customer segments, their current and future needs and outlines our roadmap in response to how we can adapt to changing customer expectations and continue to further improve overall customer satisfaction. The strategy has five key focus areas:

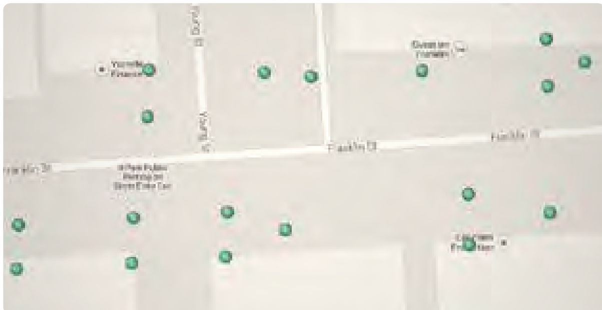
- being recognised as a national leader in the delivery of safe, reliable quality power;
- managing and maintaining a cost effective network that caters for a diverse range of electricity consumers;
- seeking opportunities to make a positive connection with communities and businesses across metropolitan and rural South Australia;
- delivering customer service that is tailored and responsive to immediate and changing needs; and
- being a trusted source of advice and information for customers' current and future electricity needs.

The Customer Service Strategy 2014–2020 is included at Attachment 6.6.

Our customers expect us to be at the forefront of new and emerging customer service initiatives to continue satisfying their expectations. Mobile devices (eg smart phones, tablets) are becoming common place, and our customers now expect information 'twenty-four seven' across multiple channels — and increasingly want self-service and self-management options. We continue to retain our focus on high quality traditional contact centre services for the many customers who still prefer this channel for at least some of their interactions with us. We have also been increasing our digital presence communication channel for those who value it.

Over the current RCP we have progressively introduced and improved self-service channels for our customers, and increased proactive communications based on customer preferences. We were the first Australian electricity distributor to offer online self-service fault reporting via internet and mobile devices. Our customers are now also able to report streetlight faults via a convenient online map (see Figure 14.1) where they can flag the specific faulty streetlight. By extending our connectivity with customers, we have increased the two-way flow of information which benefits customers and SA Power Networks.

Figure 14.1: SA Power Networks' online Faulty Street Light reporting



SOURCE: SA POWER NETWORKS 2014

Customers can also keep updated about power outages through Facebook, Twitter, our website, an interactive voice response (**IVR**) system, and via proactive updates specifically about their property via free SMS and email messages for which they can subscribe through our Power@MyPlace™ service. The following key metrics as at September 2014, demonstrate how customers are embracing these services:

- 430% increase in unique visitors to the SA Power Networks website between 2008 and September 2014;
- 121,618 registered Power@MyPlace™ customers to whom we have sent over 525,014 text messages and emails related to power outages and over 197,931 SMS and emails related to meter reading;
- over 16,686 power outages reported by our customers online via 'Report a Power Outage';
- over 79,500 streetlight outages reported via a Google map tool 'Report a Streetlight' since introduction in February 2012;
- 12,727 Facebook Fans (for 2013/14 SA Power Networks had an average Facebook audience reach of over 123,000 unique viewers per month);
- 2,845 SA Power Networks Twitter followers (for 2013/14 SA Power Networks had an average Twitter audience reach of over 121,000 unique viewers per month); and
- 1,625 Registered Electrical Contractors using our Registered Electricians Extranet System.

The Power@MyPlace™ service also gives customers the option to receive reminders for their scheduled meter reading dates to ensure we have access to the meter, enabling customers to be accurately billed for electricity use.

These recent achievements demonstrate SA Power Networks' commitment to delivering the services that customers value. However, they have generally been implemented via standalone applications. Further development in line with customer preferences requires an integrated approach to our systems development so that we have the capabilities to support evolving customer expectations. To address these system issues, SA Power Networks developed a Customer Technology Plan in 2013 which aims to deliver, amongst other things:

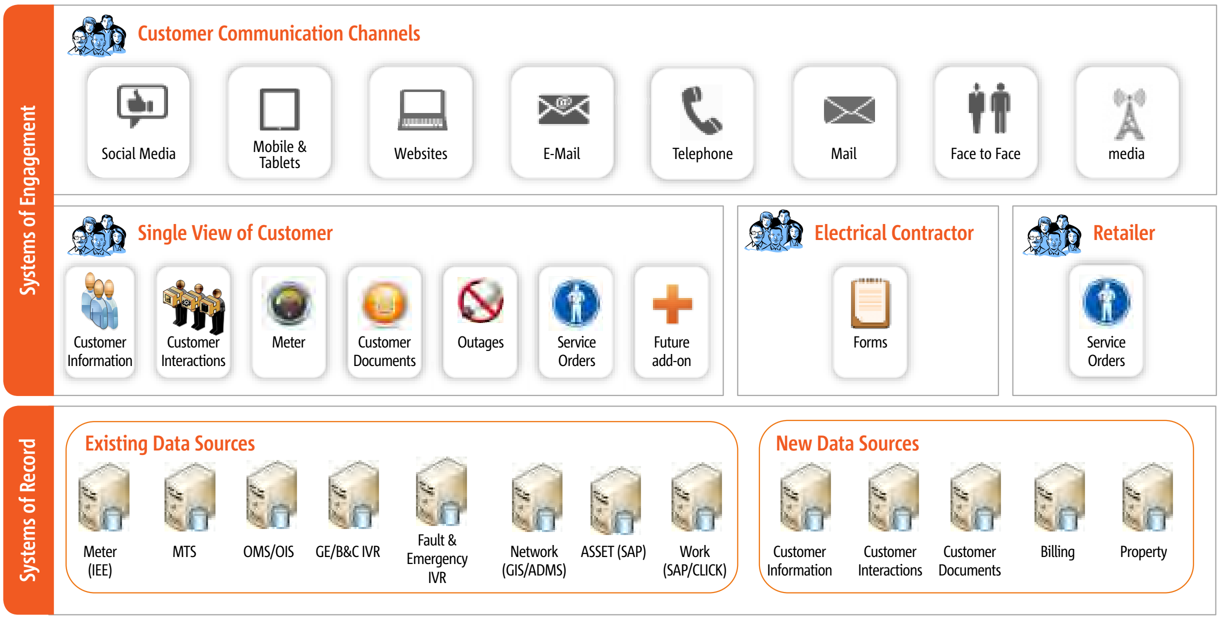
- a longitudinal, single view of customers, including their call and outage history and relevant network activity that impacts them;
- better quality customer data through a range of business driven data quality improvement initiatives;
- enhancement of our current customer communications channels through improved content, functionality and portal access;
- a repository that captures knowledge from local intelligence sources (customers, council, business and State and Federal Government), to assist and improve the reliability and quality of supply in network areas; and
- a new billing platform.

The current technology solutions in place to provide customer and billing management functions are at end of life, disparate and do not provide the flexibility required to support capabilities into the future.

SA Power Networks currently utilises various systems to support its billing and customer management activities. The main application CIS OV, provides billing capability for consumption based charges as well as a number of other functions. It is a legacy system more than 15 years old and from a technology perspective is at end of life. As the last customer using this system, vendor support will not continue and there are major limitations when requiring enhancements or functionality changes.

Collectively there are ten satellite and legacy systems delivering reporting, analytics and tracking of customer interactions including CIS OV. These systems comprise the landscape of our customer information systems, are not sustainable into the future and must be considered as part of a holistic replacement program.

Figure 14.2: A technology enabled Customer Service Strategy



SOURCE: SA POWER NETWORKS 2014

These risks associated with the use of end of life and disconnected systems to provide such critical business functionality were identified many years ago. Over the last six years we have been prudently managing these systems to extend their usability to the maximum extent and to extract the best whole of life value from them.

The reality is that these systems are now well past their use by date and must be replaced in the next regulatory period (refer Attachment 20.37).

Figure 14.2 highlights the new technology suite required to deliver on the Customer Service Strategy.

The Customer Service Technology Plan can be found at Attachment 14.1.

14.2.2
Promoting Demand Side Participation

The past five years have seen significant changes in the way that customers are using the South Australian distribution network, in particular through the adoption of solar PV and other embedded generation connected to the distribution network.

The growth of solar PV installations has occurred at a much greater rate than anticipated, and this growth is expected to continue. We now expect additional new technologies such as battery storage and electric vehicles will be embraced by customers in the future. These new technologies are challenging existing business models as our industry transitions from a hierarchical supply chain to a 'two-way network'.

The take-up of these technologies is driving three critical issues:

- **Power quality:** the preceding chapter 'ensuring power supply meets voltage and quality standards' discussed the increase in power quality issues occurring on the network due to new distributed energy resources (**DER**) technologies such as solar PV and our plans to address these;
- **Peak demand growth:** there is a need to ensure that the connection and use of these technologies is efficient. For example, excessive evening charging of electric vehicles could drive a new wave of peak demand growth and requisite network upgrades; and
- **Network tariffs:** traditional energy based tariffs are poorly aligned to the cost drivers for efficient network investment. This means that customers installing technologies such as solar PV can avoid network charges even though their network peak demand requirements are largely unchanged. For example, on residential networks the peak demand typically occurs at 7pm on a hot summer evening when PV output is low. This misalignment between costs and tariffs does little to encourage efficient investment and usage and is driving an increasing cross-subsidy from those that do not have such technologies to those that do.

Customers' adoption of new technologies is an aspect of Demand Side Participation (**DSP**), which is widely acknowledged as having the potential to significantly reduce future network investment[42][43]. If customers can be encouraged to be more active participants in the supply chain then peak demand growth can be tempered, network investment deferred or avoided, and thus network utilisation improved. Ideally, individual customers willing to 'participate' could save money, and in turn, their participation could reduce costs for all customers over the longer term.

42 Australian Energy Market Commission, FINAL REPORT, Power of choice review — giving consumers options in the way they use electricity, 30 November 2012

43 Productivity Commission Inquiry Report No. 62, Electricity Network Regulatory Frameworks, 9 April 2013

Figure 14.3: Demand side participation initiatives

Introduce cost-effective tariffs Transitioning to peak demand based tariffs to promote efficient use of the network & to more fairly apportion network costs.

Enhance customer engagement Providing information & support to enable customers to make informed energy decisions.

Maximise controllable load Partnering with customers to leverage discretionary loads to manage local network constraints.

Enable the two-way network Preparing the network to allow connection of additional embedded generation & new energy technologies.

SOURCE: SA POWER NETWORKS 2014

However, as illustrated by the issues described above, a poorly orchestrated DSP can exacerbate network issues and result in less efficient outcomes for the community as a whole.

SA Power Networks has been developing an approach to Demand Side Participation which seeks to address these issues and opportunities by providing knowledge, incentives and tools to enable customers to optimise their own energy costs and those of the community. It comprises the key components outlined in Figure 14.3 above.

This approach is described fully in our Tariff and Metering Business Case and Flexible Load Strategy, found in Attachment 14.3 and Attachment 20.34 respectively and is summarised below.

Cost-reflective tariffs

By having tariffs which more accurately reflect the cost drivers of a network business, customers will be encouraged to efficiently invest in DER as well as adopt more efficient energy usage behaviours. Cross-subsidies for those customers that have DER or large air-conditioning systems will be reduced, and strong incentives will exist for customers to use new technologies, such as electric vehicles, efficiently.

Overall, this will mean that customers whose consumption behaviour drives increases in network costs will pay for these services, while customers willing to use the network more efficiently will be able to save on their energy costs.

South Australia's climate and load characteristics are such that a network tariff with a significant peak demand based component (a 'Capacity Tariff') has the greatest cost reflectivity whilst balancing other criteria such as the need for simplicity and minimisation of bill volatility. Large business customers within South Australia have been on peak demand based tariffs for a number of years now, however, residential and small business customers have remained on 'inclining block' energy based tariffs. One reason for this is that demand based tariffs require a meter that can record the peak demand reached in each billing period, whereas the majority of residential and small business customers have basic 'Type 6' meters that can only measure accumulated energy use.

In July 2014 we introduced a new capacity tariff designed for residential and small business customers, available on an opt-in basis. From July 2017 we propose to progressively roll out this tariff for residential and small business customers who require new connections, connection point alterations and for customers making investment decisions such as investing in new DER or building a new house.

Moving customers to a capacity tariff in these circumstances maximises the benefit while minimising the cost:

- it will minimise the cost of meter replacement, since the tariff is only introduced to premises where a new meter needs to be installed. Hence the cost is limited to the small incremental cost of the more advanced meter compared to a basic Type 6 meter;
- it effectively targets customers at the critical time that they are making demand-side investment decisions for the future (solar PV or otherwise);
- it gives customers that have a low impact on the network, or are willing to change behaviour, a tool to reduce cost, by opting-in to the tariff and contributing to their meter replacement to avoid impacting other customers;
- it does not penalise customers that have invested in good faith under current arrangements, existing solar PV customers retain their benefits; and
- no customer is required to take on the tariff unless they initiate change.

Metering to support capacity tariffs

To enable the new tariff we propose to standardise on an interval meter that is 'smart ready', meaning that with the addition of a plug-in communications module, the meter could be readily upgraded to full 'smart' capability. This approach adds minimal incremental cost, and is consistent with the State Government's discussion paper on new and replacement meters[44]. It also avoids the inefficient installation of 'dumb' meters that are highly unlikely to see out their 15 year design lives.

44 South Australian Policy for New and Replacement Electricity Meters Discussion Paper, Government of South Australia Department for Manufacturing, Innovation, Trade, Resources and Energy, January 2014

We will also make the new meter our standard meter for all future asset replacements. This means that customers that have their meter replaced due to a 'bulk replacement program'[45] will receive a meter that is capable of supporting the tariff, but they will not pay any more in metering charges than anyone else and will not be required to move to the new tariff.

Based on historical data, we forecast an average of 70,000 new meters per annum will be deployed by SA Power Networks in the next RCP. From July 2017, around 56,000 customers per annum will move to the new tariff.

Meter reading

Small customers in South Australia with standard metering currently have their meters read, and their bills issued, quarterly. With the introduction of the new capacity tariff, we consider it critical to provide customers with monthly bills so that they are able to correlate their peak demand with their behaviour during the period and hence be able to respond most effectively. Monthly billing will also assist customers to manage their energy bills and reduce bill 'shock'.

Because the roll out of capacity tariffs is not geographically based, reading meters for capacity tariff customers monthly is more costly than the current cyclical quarterly reads. In the early years while only the opt-in tariff exists, we will undertake special reads of these advanced meters to enable monthly billing. By 2017 we expect that there will be sufficient penetration of advanced meters that it will be cost effective to transition to monthly read and billing for all customers.

Metering contestability

SA Power Networks is currently the monopoly provider of the basic manually-read accumulation meters (Type 6 meters) used by around 750,000 residential and small business customers in South Australia and is the responsible service provider for meter reading services. Under a proposed NER change arising from the Power of Choice review[46], metering services are to become fully contestable, with the customer's retailer able to appoint their own Metering Coordinator (**MC**). These proposed reforms are subject to consultation that will run until 2015, with final NER changes expected to come into effect in 2016.

Our Proposal to move to a smart-ready meter as our standard regulated meter is compatible with our likely future role as the default MC for our existing Type 6 meters when metering contestability commences.

We are seeking to ensure under the Rules that any market-led meter replacement:
- requires minimum meter specifications be set so that the new meters enable our capacity tariff and the network functions we require;
- provides a central gateway for meter access, so we can access data from third party meters in a timely manner via a standard interface;
- enables appropriate exit fees (or equivalent) to be applied; and
- ensures that our investment in meters made under the current regulatory framework can be appropriately recovered.

Irrespective of whether SA Power Networks or a third party provides meters and metering services in a contestable environment, SA Power Networks will need to invest in systems and processes to utilise interval data for network billing and operations.

Our approach to metering:
- ensures that customers can be transitioned to a more cost-reflective network tariff;
- enables us to continue to offer a basic regulated metering service in the 2015–20 RCP, a period during which we expect a transition to full contestability in metering services;
- is compatible with the NER as it stands today;
- aligns with likely outcomes of the Rule change process, and State Government policy direction; and
- will be compatible with our likely future role as the incumbent Metering Coordinator in a contestable market.

We will monitor developments with State Government Policy and the AEMC Rule change due to be finalised in April 2015. If required, we will adjust our metering proposals in our revised Regulatory Proposal due to be lodged in July 2015.

Controlled load

Our Flexible Load Strategy (Attachment 20.34) proposes a number of initiatives to better utilise the controllable load potential within South Australia. For example, more efficient use of existing equipment such as electric hot water systems, air-conditioning, and pool pumps, as well as new equipment such as electric vehicles, could significantly improve network utilisation and efficiency. In contrast to approaches taken in the past, these initiatives will generally not rely on direct load control by SA Power Networks. We will provide customers with the appropriate pricing signals, education and tools to enable them to respond themselves, whilst also establishing foundations to make technologies such as Direct Load Control more economic into the future.

Customer and retailer engagement

Cost-reflective tariffs, advanced metering, our controlled load initiatives and changes to our meter reading and billing practices need to be supported with substantial customer education and information materials. Customers have become accustomed to reducing consumption as their primary means to reduce their electricity bill and generally do not focus on how to manage their peak demand to reduce network costs. SA Power Networks will seek to influence behaviour by educating customers on these initiatives and the options available.

Significant retailer engagement will also be required to set up the policies, procedures and systems to bill small market customers in this new way.

Enabling the two-way network of the future

SA Power Networks' Demand Side Participation initiatives, in combination with work being undertaken to manage

45 SA Power Networks typically replaces around 10,000 meters per annum in bulk replacement programs undertaken when a batch(es) of meters fail sample testing procedures or need replacement for other reasons.

46 Power of choice review — giving consumers options in the way they use electricity, Final Report, Australian Energy Market Commission report EPR0022, 30th November 2012.

quality of supply as described in Chapter 13, will provide key underpinnings in the efficient transition to the two-way network of the future. The strategies will encourage customers to invest and use new technologies in such ways that manage growth in peak demand, reduce the need to augment assets, and therefore ultimately improve energy affordability not only for individual customers, but for the entire community.

14.3

What our stakeholders and customers have said to us, and our response

14.3.1
Understanding our customers' concerns

During the Research stage of our TalkingPower consultation program and in the context that any investments and operating costs would result in no more than a CPI increase in their network charges, our customers and key stakeholders confirmed that:

- customers have new expectations about how and when we communicate with them and they want more information about the electricity industry;
- 61% of customers surveyed said we should be proactive and responsive, and continue to improve our interactions with them;
- customers clearly expressed a need for education on new technologies and changes to the industry;
- customers still value contact centre services;
- 78% of customers surveyed supported the installation of advanced meters to allow them to exercise a greater deal of control over their electricity use;
- customers support SA Power Networks upgrading the network to allow two-way flows and enable the increasing uptake of new technologies; and
- 68% of customers support the phased introduction of tariffs that more closely reflect usage of the network.

14.3.2
Integrating customer feedback into our business planning process

These insights were incorporated into our planning for the next RCP and a range of key investment options were communicated back to customers and stakeholders for confirmation and comment. These investment priorities were then more broadly consulted on in our 'Directions and Priorities 2015 to 2020' consultation document. The investments include:

- further develop self-service options that our customers value;
- develop multi-channel communication tools to interact with our customers;
- undertake initiatives to enable an efficient and fair transition to a two-way network to facilitate continued take-up of solar PV systems and other embedded generation that feed excess energy into the network;
- strengthen data collection and information flows from our field personnel to customers, to provide accurate and timely information on service and restoration activities;
- implement systems to allow a single view of the customer and enable the service to be tailored and responsive to their needs;
- implement our Customer Technology Plan;
- be a trusted source of information and advice for customers' current and future electricity needs;
- introduce cost reflective tariffs to promote efficient customer investment in DER;
- progressively implement a targeted roll-out of advanced meters and cost reflective tariffs to give customers more control over energy use and peak demand; and
- maintain a reliable secure network billing service by replacing our end of life systems.

14.3.3
Feedback received on our 'Directions and Priorities 2015 to 2020' consultation document

Responses to the Directions and Priorities document with respect to 'serving customers now and in the future' were:

Business SA submission:

- "Business SA recently conducted a workshop with its members to gauge the impact rising electricity prices were having on them and 64% of the workshop attendees were looking at measures to improve energy efficiency, lower usage or lower peak demand."
- "From Business SA's pre-State election survey of members, 80% of respondents supported investment in a smart grid, including the roll out of smart meters, in order to bring down costs of managing the grid and lower supply charges. We endorse SAPN's focus on smart meter technology and the drive to facilitate further connection of new technologies to advance the two-way network of the future."
- "We would also like to understand how SAPN plans to structure their smart meter tariff structure such that retailers can dovetail in with innovative tariff offerings to end users, including small businesses."
- "We encourage SAPN's aim to adapt to the changing ways in which consumers use the electricity network, including through enabling the installation of battery storage. It is becoming increasingly evident that battery storage will play a major role in reducing consumers' reliance on the electricity grid, particularly during peak periods. There are also various options for SAPN to employ storage through its network as an alternative to other forms of capital investment which has begun to occur interstate. We would like to see more detail in the regulatory Proposal as to any plans SAPN has for distributed energy storage throughout its network."
- "We acknowledge SAPN's recent announcement that consumers with battery storage will no longer be able to claim solar feed-in-tariff premiums from the State Government. While we accept the technological constraints on cost efficiently delineating energy fed directly into the grid from solar panels, as opposed to coming from a battery, we would like to see an acknowledgement in the regulatory proposal that SAPN will revisit this constraint should the technology become viable."
- "The introduction of smart meters must enable consumers, including small businesses, to take proactive measures to reduce their electricity costs. Furthermore, while we acknowledge the upfront cost of installing smart meters, we have always understood that they will ultimately reduce the costs of managing the grid, one simple example being the reduced need for manual meter reads. We accept that some of the grid management savings associated with smart meters will

only be realised with economies of scale and that the current State Government's New and Replacement Policy may take some time to achieve a high penetration of smart meters. However, any savings that smart meters create for SAPN should be passed back to consumers and we are concerned that the advised 'small incremental annual cost of installing smart meters' will become embedded into the tariff structure."

Minister for Mineral Resources and Energy submission:

- "While I appreciate the difficulty in forecasting demand in the current environment, I encourage SA Power Networks to assess its Proposal against the emergence of more distributed generation, in particular with battery storage, competitive advances in metering infrastructure and innovative network tariffs signalling a movement away from a centralized grid model needing expansion."
- "The Government supports the competitive provision of advanced meters. The Australian Energy Market Commission (**AEMC**) is currently developing Rules to facilitate a competitive market for the provision of advanced meters to consumers. Earlier this year, the Government also released a discussion paper entitled South Australian Policy for New and Replacement Electricity Meters under which it was proposed that smart ready meters be installed in new and replacement situations unless a customer chooses to opt-out. This Proposal is intended to work under the Rules being developed by the AEMC. Any approved expenditure in this area will need to take into account the impact of competition in residential advance metering installations."

COTA SA submission:

- "The introduction of smart meters and related technology should accrue benefit to the consumer."

Residential customer submission:

- One residential customer made the submission "No smart meters — just provide accurate meters".

14.4

SA Power Networks' response to consultation, and proposed expenditures

We have considered the feedback from customers and stakeholders regarding key service priorities, how the distribution network will be used in the future and our own readiness to meet these from a capability, technology and information perspective.

Customers and stakeholders responses have consistently supported our proposed investments program in regard to 'serving customers now and in the future'. These investments include:

- implementing our Customer Service Strategy to deliver customer service options that our customers will value, provide accurate and timely information, cater for a diverse range of electricity consumers and provide a service that is tailored and responsive to our customers' immediate and changing needs;
- undertaking initiatives to facilitate the phased introduction of socially equitable cost-reflective pricing;
- targeted upgrades to the network to allow two-way network flows and enable an increasing update of new technologies;
- customer engagement to provide education to customers on demand side participation including new tariffs, network controlled loads and using electricity more efficiently; and
- in conjunction with the above initiatives, increase our corporate communications and information materials to support the above investments, improve customer understanding of our role in the market and assist customers make informed choices and help manage costs.

Adaptions to changing customer expectations

While customers rate the overall customer experience as positive there is room for improvement. Primarily, customers expect a consistent and proactive service response across all interactions and communication channels, and for current website information and tools to deliver better experiences.

In considering feedback from customers regarding key service priorities, and our own readiness to meet these from a capability, technology and information perspective, the Customer Service Strategy provides steps to realise our new customer service vision for 2020: We will provide proactive, responsive, and reliable service to meet our customers' needs, now and in the future. Initiatives include:

- further develop self-service options that our customers value;
- increase the use of social media (Facebook, Twitter), mobile (SMS, text messaging) 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;
- replacing our end of life billing system;
- upgrading our market facing systems for business-to-business transactions;
- implement our Customer Service Technology Plan;
- be a source of trusted advice and information for customers' current and future electricity needs; and
- continue to develop the multiple communication channels that customers now expect from businesses.

In order to implement these initiatives we must upgrade our information systems and work processes, including improved IT and communications systems, workforce mobility systems and enhanced asset management capabilities, amongst other areas.

Promoting Demand Side Participation

In order to promote demand side participation, there are two key expenditure areas for the 2015–20 RCP, including:

- introducing cost-reflective tariffs to promote efficient customer investment in DER and reduce existing cross-subsidies between different customer groups; and
- introduction of smart ready meters as our standard meter for small customers to enable cost-reflective tariffs and enable customers to better control their energy use and manage peak demand.

From 1 July 2015 we will install smart-ready meters for:

- all new connections and upgrades to supply: where the customer would have received a new meter in any case;
- customers wanting to 'opt-in': where a customer voluntarily takes up the new tariff on the basis of anticipated benefits, and can thus factor in the cost of a metering upgrade as part of their decision making; and
- bulk change replacement meters.

This will avoid continuing with the installation of inefficient accumulation meters which are highly unlikely to meet future customer needs.

We will undertake a comprehensive program of process and system enablement and retailer and customer engagement to support the current opt-in capacity tariff and to design and be ready for the introduction of mandatory capacity tariffs from 1 July 2017.

Specifically, SA Power Networks will undertake upgrades of our IT systems and processes to manage the increased volumes of customer, metering and network data. These upgrades will also prepare us to support our role as the default MC when full metering contestability commences and to ensure that the market benefits of any third party deployments of smart meters can be realised.

Table 14.1 outlines the key capital expenditures proposed for the 2015–20 RCP and Table 14.2 details changes to Standard Control Services (**SCS**) operating costs above the efficient base year. Step changes in Alternative Control Services (**ACS**) operating costs, associated with increasing the frequency of reading meters from quarterly to monthly, are outlined further in Section 21.13. Further detail on specific capital and operating items can be found in the referenced sections of this Proposal.

Table 14.1: 'serving customers now and in the future' — capital expenditures

Item	2015–20 RCP 2015$	Reference section
Billing system replacement project (CIS OV/CRM replacement)	58.4	20.8.1
Customer self service enhancements & customer call management system replacement	8.3	20.8.1
Field mobility enhancements	11.1	20.8.1
Tariff and metering (applications and equipment)	27.0 (SCS) 49.0 (ACS)	20.8.1 20.9
Capex Total	**\$104.8m (SCS)** **\$49.0m (ACS)**	

Table 14.2: 'serving customers now and in the future' — operating step changes expenditure

Item	2015–20 RCP 2015$	Reference section
Tariff and metering	33.8 (SCS) *86.2 (ACS)	21.6 21.13
Customer support and communication	8.2	21.6
Opex Total	**\$42.0m (SCS)** ***\$86.2m (ACS)**	

*Total ACS operating expenditure shown.

14.5

Benefits to customers

These Proposals will provide the following benefits to South Australian customers:

- compliance with regulated obligations;
- enhanced self-service customer service options;
- more accurate and timely restoration service information for customers;
- accurate and timely information for customers so they can understand and manage their electricity costs;
- more cost-reflective signalling of network costs for small customers;
- reduced cross-subsidisation between customers with or without large air-conditioning systems and DER such as solar PV panels;
- alignment with South Australian Government policy directions on metering and tariffs; and
- alignment with customer expectations as revealed in our Customer Engagement Program.

15 Fitting in with our streets and communities

15

Key points

- Our network assets have historically been designed and constructed with performance, reliability, safety and cost efficiency in mind with low priority given to their aesthetic appeal.
- Significant and persistent community concern over the aesthetics of our assets and activities has been highlighted in our TalkingPower program, in terms of current approaches to tree trimming, limited undergrounding of power lines, and substation facades.
- Extensive consultation and research on tree trimming has shown there is a willingness to pay for enhanced vegetation management approaches across the State.
- The community and a range of key stakeholders strongly support a move away from a one-size-fits-all approach and working towards a more sustainable and long-term approach that includes improved trimming practices.
- During the 2010–15 RCP SA Power Networks has focused on compliance with regulatory obligations around vegetation clearance distances and managing community safety risks, and ensuring an aesthetic outcome has been challenging.
- In the 2015–20 RCP, we propose to enhance our vegetation management systems and practices to improve vegetation management outcomes in the long term (in line with community preferences, but within legislated requirements), continue undergrounding projects under the Power Line Environment Committee program, and continue to build fit-for-setting substation facades where it is cost-effective to do so.

15.1

Our regulated obligations

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 consumers with respect to the price, quality, safety, reliability and security of electricity supply (ie the primary focus of the national electricity objective or **NEO**) there are a number of specific regulatory obligations which SA Power Networks is required to meet in 'fitting in with our streets and communities' including:

- we must **inspect and clear vegetation** from around power lines at regular intervals (which cannot exceed three years) in accordance with prescribed requirements, under the South Australian Electricity Act 1996 (**Act**) and Electricity (Principles of Vegetation Clearance) Regulations 2010 (**Regulations**);
- SA Power Networks is responsible for periodic programs for undergrounding of power lines as defined in Part 5A of the Act (Undergrounding of Power lines); and
- SA Power Networks is responsible for a prescribed amount of undergrounding power lines as defined in the Act and in Part 9 of the Electricity (General) Regulations 2012, and managed by the Power Line Environment Committee.

15.2

Key issues in 'fitting in with our streets and communities'

Our electricity assets are designed and constructed with performance, reliability, safety and cost efficiency in mind. Above ground assets are interspersed among people, homes, buildings, schools, shopping centres, streetscapes, roads and highways, and while cost effective, their visual impact is often not appealing.

SA Power Networks recognises that we have an important role in the economic, social and environmental fabric of our community and acknowledges the importance the community places on both safety and visual amenity in terms of trees in urban and regional settings, and how our infrastructure fits in with changing community needs.

In our TalkingPower Customer Engagement Program, while electricity customers recognise that the high cost of underground power lines makes extensive undergrounding prohibitive, they identified bushfire, road safety, other high risk areas, along with visual amenity (ie how the streetscape looks) as priority areas for undergrounding the electricity network. Our consultation tested a prioritised program of enhanced vegetation management and undergrounding approaches for NBFRAs and BFRAs, which includes HBFRAs.

The key areas of focus in 'fitting in with our streets and communities' are:

1. managing vegetation management outcomes;
2. undergrounding power lines under the Power Line Environment Committee program; and
3. fit-for-setting substations.

15.2.1
Managing vegetation management outcomes

Under the Act and Regulations trees must be kept clear of overhead power lines to prevent damage to power lines and interruption to supply, but most importantly to safeguard the public against shock and damage to property.

SA Power Networks is required to inspect and clear vegetation from around overhead power lines so that prior to the next scheduled inspection and clearance (at a maximum of three yearly cycles) the vegetation does not grow, regrow or bend into the 'clearance zone' around the power line, in winds that might reasonably be expected in the area.

In accordance with the Regulations, SA Power Networks is not permitted to clear vegetation beyond the applicable 'buffer zone' surrounding the power line for the purposes of enhancing the appearance, stability or health of remaining vegetation.

SA Power Networks currently inspects and clears vegetation according to the prescribed requirements across the State. Every year we inspect about 50,000 km of power lines in BFRAs with the remainder lying in NBFRAs. Each year, on average around 8,000 km of vegetation in BFRAs is subject to clearance. In NBFRAs about 15,000 km of vegetation is inspected and cleared where necessary (at least every three years).

The expectations of the community have evolved since the legislative framework was put in place after the 1983 Ash Wednesday bushfires. At that time there was an understandable and single-minded focus on community safety. A review of the Regulations commenced in 2008/09, and changes came into effect in 2010, allowing a more risk based approach to be adopted in the Adelaide metropolitan areas, although the requirements in BFRAs and regional communities remained unchanged. Today the community is seeking more holistic and sustainable approaches that ensure safety and maintain sustainable trees and environments.

We currently spend about $36 million annually on vegetation management. This program is based on a cost-efficient approach where most trees are pruned every three years. Since risks are much higher in BFRAs we undertake a one year inspection and clearance cycle in these areas and a three year cycle in NBFRAs.

Community concern

Balancing the very specific and legislated responsibility for vegetation clearance around power lines with community expectations around sustaining our urban and regional trees and ensuring an aesthetic outcome is challenging. Recognising these tensions, SA Power Networks has undertaken extensive consultation with the community, Councils and Local Government Association (**LGA**) on the topic.

There are a number of ways in which the impact of tree trimming can be reduced or avoided, including:

- public education and awareness of appropriate species for planting underneath or near power lines;
- more frequent cycles of tree trimming;
- tree removal and replacement (by planting the right trees for a positive net impact on the environment);
- relocation of power lines;
- removal of existing power lines;
- alternative asset design; and
- undergrounding of power lines.

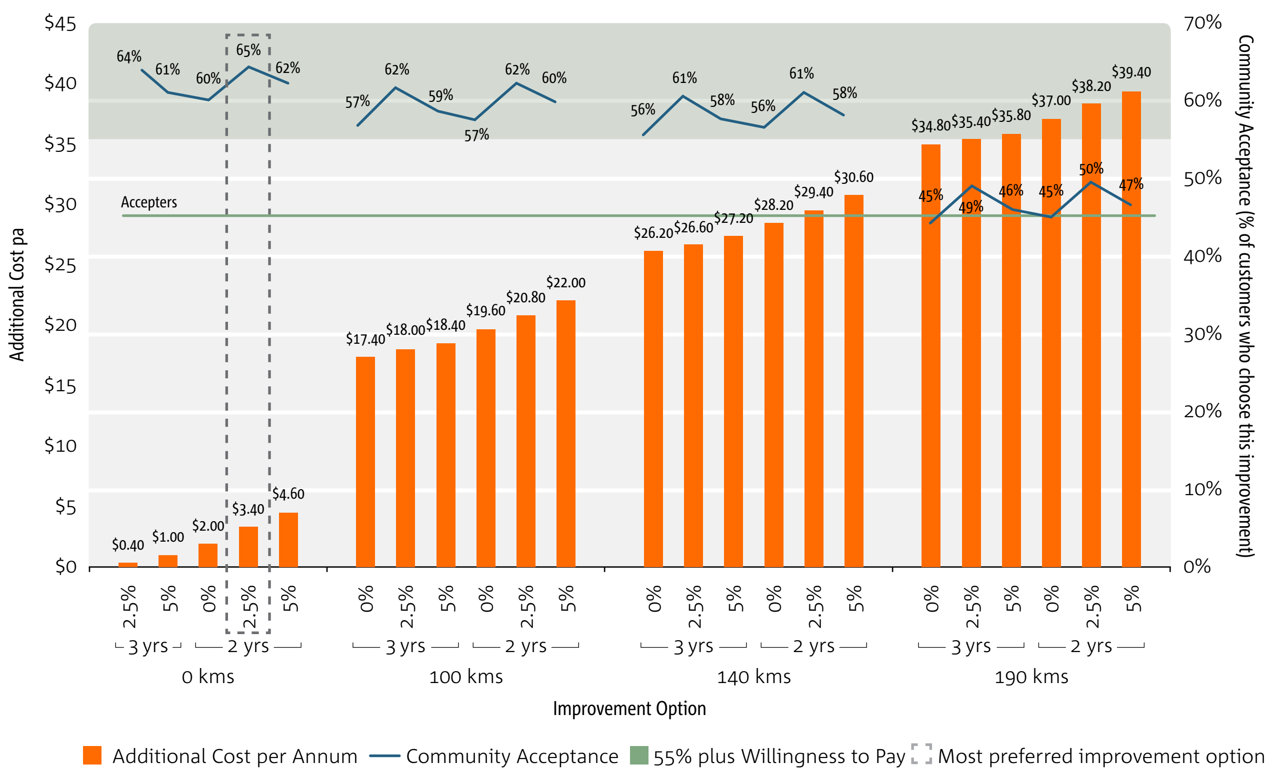
During our Customer Engagement Program a targeted workshop on vegetation management was held and customers and subject matter experts together explored alternative vegetation management strategies and approaches. Customers recognise that the high cost of underground power lines makes extensive undergrounding prohibitive, however there was a common view that more could be done with a prudent strategy that places greater emphasis on longer term vegetation management solutions, managing community safety risks and enhancing stakeholder participation.

As indicated in Chapter 11, our customer consultation extended to developing a range of vegetation management options based on stakeholder-derived principles, and then testing customer value and price sensitivity via Willingness to Pay research. This type of research involves customers making choices in relation to alternative improvement initiatives which are accompanied by realistic incremental charges to the customer.

Figure 15.1 shows community Willingness to Pay in terms of percent of the research sample (blue line) who would choose the specific improvement initiative tested. The orange bars show the estimated incremental annual amount customers would be asked to pay for that improvement initiative.

The chart is organised into four groups, corresponding to four levels of undergrounding tested (0, 100, 140 and 190 kms). Within each of these groups there are four or five different vegetation management options. These options related to varying levels of removal and replacement of inappropriate vegetation beneath power lines in terms of the number of spans subject to inspection and clearance (0%, 2.5%, and 5%) and the length of the tree trimming cycle (2 or 3 years). The green 'accepters' line shows the percentage of respondents who accepted all improvement options presented to them relating to non-bushfire risk areas.

Figure 15.1: Willingness to Pay by specific improvement tested — NBFRAs



SOURCE: THE NTF GROUP, SA POWER NETWORKS TARGETED WILLINGNESS TO PAY RESEARCH — RESEARCH FINDINGS, THE NTF GROUP PTY LTD, JULY 2014.

At least 55% of the community in the choice research were prepared to pay for seventeen of the twenty-three improvements tested in relation to NBFRAs with strong support for willingness to pay up to $30.60 per annum for specific improvements which equates to $331 million of investment. The grey dotted box highlights the most preferred improvement option in NBFRAs. 65% of customers surveyed were willing to pay up to $3.40 annually for tree removal and replacement programs combined with an increase in tree trimming frequency (from three years to two years) to reduce the impact and severity of tree pruning, improve visual amenity and provide the potential for improved tree health.

For customer segmentation information please refer to the Willingness to Pay research report Attachment 6.8.

Local Government support
Local Government is also a key stakeholder in relation to vegetation management and SA Power Networks has been actively engaging with Local Government stakeholders to discuss issues associated with vegetation management and explore opportunities for partnerships in programs or initiatives. Engagement includes an annual Local Government forum on vegetation management, joint tree removal trials, and the development of two reference groups — a Local Government Association/Council Working Group and an Arborist Reference Group, to progress strategic initiatives and develop a protocol for vegetation management near power lines.

A vegetation management discussion paper titled “SA Power Networks’ long-term plan for managing trees near power lines” (refer Attachment 6.9) was also developed in consultation with Local Government and feedback on the direction, strategies and initiatives outlined in this document was sought through the LGA. The LGA has expressed its support for the initiatives and strategies outlined in the discussion paper following feedback received from local Councils.[47]

Tree removal and replacement programs
In addition to the current tree trimming requirements, a program of removing inappropriate vegetation is a practical alternative that can achieve clearance near power lines and reduce ongoing clearance requirements. Inappropriate vegetation may include unstable trees, trees growing too close to power lines, fast-growing species and self-seeding saplings. Trees being considered for removal are evaluated and assessed against a range of community, legislative and environmental factors, and removal is subject to financial cost benefit analysis.

In consultation with local communities and land owners this initiative will include a vegetation replacement program for ongoing environmental benefit. This may include planting appropriate shrubs under power lines, planting saplings or trees nearby or contributing to a habitat fund.

Over time the tree removal and replacement programs are expected to reduce costs related to ongoing tree trimming requirements. For the 2015–20 RCP the expected savings on the tree trimming from tree removal/replacement has been forecast at $10.5 million over the period.

47 Local Government Association of South Australia, Submission — Directions for Vegetation Management, 30 June 2014.

Change in vegetation trimming in NBFRA
There has been ongoing concern from Councils, particularly in the metropolitan area, on the current trimming practices and outcomes based on the three year cycle specified under the Regulations. A shift to a shorter inspection and cutting cycle in metropolitan areas and rural townships would allow more frequent tree trimming to be undertaken in areas where high value is placed on street trees and visual amenity. It will ultimately result in less severe cutting whilst enabling us to meet our legislative requirements.

SA Power Networks intends to trial and assess more advanced tree trimming practices, including techniques that limit regrowth and epicormic growth, and taking into account good horticultural practices and species requirements, in consultation with expert arborists. The trials will allow for evaluation of factors including trimming time and cost impacts, impacts on compliance with Regulations, and the long-term benefits of these practices in terms of tree health and amenity.

15.2.2
Undergrounding power lines under the Power Line Environment Committee program

SA Power Networks generally constructs all new assets overhead, except in new subdivisions which are undergrounded.

However, we do undertake limited and targeted undergrounding of power lines in specific areas through the State Government Power Line Environment Committee (**PLEC**) program. PLEC is a program of undergrounding power lines to improve the aesthetics of the electricity network for the benefit of the general community having regard to road safety and the provisions for electrical safety pursuant to the Act.

Total annual PLEC spend is capped at around $9.5 million and SA Power Networks funds two-thirds of each new project with councils funding the remainder. Project applications are prioritised according to the PLEC Charter, approved by the Minister and this program is widely supported by the community and stakeholders.

However, in our TalkingPower consultation, electricity customers identified bushfire, road safety, and other high risk areas as priority areas for undergrounding the electricity network, recognising that the high cost of underground power lines makes extensive undergrounding prohibitive. Consequently, while customers supported the continuation of the PLEC program they were not supportive of additional expenditure on undergrounding solely for aesthetic reasons.

15.2.3
Fit-for-setting substations

Community consultation recognised the community benefits of fit-for-setting facade treatments given that many of our 400-plus substations are set in cities and suburbs. Notwithstanding this, customers consider that a focus on this issue should only occur where work is scheduled for other reasons.

In these cases if there is sensitivity to substation appearance then SA Power Networks in consultation with the community should explore the opportunity to improve a substation's fit-for-setting amenity at low incremental cost.

SA Power Networks has been implementing such an approach in recent years, which has been welcomed by local communities.

15.3

What our stakeholders and customers have said to us

15.3.1 Understanding customers' concerns

During the Research stage of our TalkingPower consultation program we provided some relevant information on key topics and asked our customers and key stakeholders what they expected from SA Power Networks over the next five years and beyond. This was done in the context that any investments and operating costs would be managed within no more than a CPI increase in their network charges. Specifically, with respect to 'fitting in with our streets and communities', our TalkingPower consultation program confirmed that:

- 79% of customers supported strategies for managing vegetation to create a more pleasing visual result whilst delivering on community safety and legislative obligations;
- 73% of customers supported tree removal and/or replacement with more appropriate vegetation;
- 79% of customers supported more frequent trimming cycles;
- customers support SA Power Networks' continued commitment to PLEC;
- 86% of customers supported other prioritised initiatives for undergrounding the network; and
- 76% of customers supported improving the facades of substations with the greatest community benefit.

15.3.2 Integrating customer feedback into our business planning process

While SA Power Networks' vegetation management program has focused on maintaining safety, we do understand that this must be balanced with community concerns about the appearance of trees. It is evident not only through our comprehensive stakeholder and customer engagement process, but also through customer complaints, that the community is concerned about the severity of tree trimming due to the frequency of pruning and the effects of pruning on tree health and the visual appeal of metropolitan and regional areas.

Customer insights were fed into our planning for the next RCP and a range of key investment options were communicated back to customers and stakeholders for confirmation and comment. These investment priorities were then more broadly consulted on in our 'Directions and Priorities 2015 to 2020' consultation document. The investments included:

- implementing an enhanced program of vegetation management to improve tree-trimming outcomes in the long-term;
- continued undergrounding of power lines in specific areas through the State Government PLEC program; and
- building fit-for-setting substation facades where appropriate and cost effective.

15.3.3 Feedback received on our Directions and Priorities 2015 to 2020 consultation document

Responses to the 'Directions and Priorities 2015 to 2020' consultation document with respect to 'fitting in with our streets and communities' were:

Business SA submission:

- "Business SA notes that a significant portion of the increase in SAPN's tariffs for 2014/15 stemmed from the AER decision to allow a pass through for vegetation management."
- "SAPN advises that it currently spends approximately $40 million per annum on vegetation management with 'costs driven by highly prescriptive statutory requirements in terms of inspection regimes and clearance zones around power lines' and goes onto say that 'there is a need to move away from a one-size-fits-all approach and work towards a more sustainable and long-term approach that may include strategic removal and tree replacement and improved trimming practices' … Business SA supports SAPN's pragmatic approach and suggests that it outlines in its regulatory Proposal what legislative changes are necessary to adopt a more efficient approach to vegetation management. At this same time, can SAPN provide details of the likely cost savings from adopting this approach?"

Minister for Mineral Resources and Energy submission:

- "Following last year's … pass-through cost for vegetation clearance costs resulting from increased rainfall, the Government received a number of letters expressing customer concern regarding the additional charge. The view expressed to SA Power Networks during community consultation may not necessarily be the view held by the majority of consumers."
- "In addition, the vegetation clearance regulations under the Electricity Act 1996 were amended in February 2010 to allow SA Power Networks to adopt a risk-based approach for pruning vegetation around low voltage lines in non-bushfire areas of Adelaide representing a less burdensome regulatory requirement. Given these factors, SA Power Networks should consider whether increased costs for vegetation clearance are necessary."

COTA SA submission:

- "In the coming years, there needs to be a review of the frequency and form that vegetation management takes that weighs public safety and amenity against cost to the consumer."

Central Irrigation Trust submission:

- "We oppose the vegetation management strategy outlined and would like to see a more efficient and cost-effective process employed if one needs to be employed at all."

Residential customer submission:

- "Dollars spent on repetitive tasks such as tree pruning, replacement of timber wire cross members, and lives lost by vehicles hitting power poles. The government should have taken this direction instead of outsourcing such responsibility to commercial interests. The costs are significant and never ending in the existing non-sustainable infrastructure hardware design."
- "I see continuing pruning of trees that grow up through power lines in rural areas as fundamentally stupid. It is an absolute waste of resource, and so a failure of management process. The alternative is to simply cut large trees under power lines down, but if power lines were undergrounded, they could be left standing."
- "The trees are on Council land so get them to trim them or remove them."

15.4

SA Power Networks' response to consultation, and proposed expenditures

The prescriptive nature of the clearance requirements limits SA Power Networks' ability to meet the safety and reliability requirements in an aesthetically pleasing way. With regard to 'fitting in with our streets and communities', feedback from stakeholders and customers has expressed widespread support for programs aimed at:

- ensuring legislative compliance and preserving community safety;
- providing a more strategic and sustainable long term program to reduce tree trimming requirements;
- vegetation management initiatives that consider visual outcomes;
- underground power lines in a prioritised program of undergrounding in high bushfire risk areas, and for improved road safety;
- building fit-for-setting substation facades where appropriate and it is cost effective to do so;
- ongoing community consultation; and
- improved communication and education.

We have acknowledged that there is a need to move away from a one-size-fits-all approach and work towards a more sustainable and long-term approach. This entails ongoing work with the community, councils and the LGA to develop a collaborative plan and implement initiatives such as strategic tree removal programs and improved tree trimming practices.

The consultations and consumer research has confirmed that South Australians are placing increasing importance on managing community safety from bushfires but there is also a willingness to address the severity and frequency of tree trimming and the potential for consequent impact on tree health and visual amenity.

Our program of expenditures for the 'fitting in with our streets and communities' service area includes projects that:

- implement an enhanced vegetation management program that is focused on the long-term, balancing risk, compliance and customer expectations;
- manage community expectation around visual outcomes;
- continue undergrounding of existing power lines in specific areas through the State Government PLEC program; and
- implement fit-for-setting substation facades when it is cost effective to do so.

As well, SA Power Networks will continue working with the community and develop partnerships to improve vegetation management outcomes. Our ongoing engagement initiatives will include:

- liaison and partnerships with Councils;
- improved community education and engagement;
- developing partnerships with key organisations to improve tree knowledge and vegetation management outcomes, including educational and research institutions and government agencies;
- continuing to work with the LGA/Council Working Group and Arborist Reference Group;
- investigating establishment of Regional Advisory Groups to improve vegetation management;
- mechanisms for collating and managing feedback; and
- seeking amendments to vegetation clearance regulations to permit the risk based approach in regional towns.

SA Power Networks acknowledges the desire of respondents to our Directions and Priorities consultation to reduce the cost of vegetation clearance and considers the implementation of the strategies outlined above will enable cost to be prudently managed over the long term.

Table 15.1 outlines the key capital expenditures proposed for the 2015–20 RCP and Table 15.2 details changes to operating costs above the efficient base year. Further detail on specific capital and operating items can be found in the referenced sections of this Proposal.

Table 15.1: 'fitting in with our streets and communities'— capital expenditures

Item	2015–20 RCP 2015$	Reference section
Power Line Environmental Committee	46.3	20.6.6
Capex Total	**$46.3m**	

Table 15.2: 'fitting in with our streets and communities'— operating step changes expenditures

Item	2015–20 RCP 2015$	Reference section
Vegetation Management — Shift to a NBFRA 2 year cycle	13.5	21.6.3
Vegetation Management — NBFRA Tree Removal & Replacement program (2.5%)	6.1	21.6.3
Vegetation Management — Advanced Tree Trimming practices (Arborists)	1.9	21.6.3
Vegetation Management — Corporate Communications	1.2	21.6.3
Opex Total	**$22.7m**	

15.5

Benefits to customers

These Proposals will provide the following benefits to South Australian customers:

- compliance with regulated obligations;
- improved community aesthetics and amenity;
- reduced vegetation management costs in the long term;
- alignment with specific customer preferences as revealed in Willingness to Pay discrete choice modelling; and
- alignment with customer expectations as revealed in our Customer Engagment Program.

16 Capabilities to meet our challenges

16

Key points

- The most significant and transformative change in the distribution sector since the establishment of the NEM will occur over the next five to 10 years.
- In delivering our proposals for 2015–20 SA Power Networks will build our organisational capabilities to prudently and efficiently deliver the outcomes sought by customers.
- While we are guided by our strong governance, planning systems, Future Operating Model and Customer Service Strategy, investment in our people, our information systems, our depot facilities and fleet are necessary to ensure we have a sufficient and competent skilled workforce suitably equipped to deliver these services.
- Enhancing our integrated information and systems capabilities will have major benefits for customers and SA Power Networks into the future. Enterprise information management systems will revolutionise our ability to efficiently manage assets through their life cycles, enhance valuable information access opportunities for customers and enable our dispersed workforce to retrieve the information they need, when they need it.
- In the 2015–20 RCP, we propose to continuously improve our comprehensive governance systems, maintain advanced stakeholder engagement and long term planning approaches, align our culture to support enhanced customer service and outcomes, ensure we have the right mix of internal and external resources to deliver on our work programs, and have safe and fit-for-purpose property, systems, equipment, and fleet resources.
- SA Power Networks will continue to be a major employer in our State.

16.1

Our regulated obligations

In conducting our business we must comply with the many legal obligations that cover safety and employment arrangements. 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 consumers with respect to the price, quality, safety, reliability and security of electricity supply (ie the primary focus of the national electricity objective or **NEO**) there are a number of specific regulatory obligations which SA Power Networks is required to cover safety and employment arrangements including:

- our employees have heavy vehicles and travel more than 18 million kms during the year. We have in place processes and business rules to meet fatigue management obligations, including those under **Heavy Vehicle National Law (South Australia) Act 2013**, and the **Approved Code of Practice Working Hours (South Australia) 2010**; and
- ensuring our safety systems meet obligations under **National Harmonisation of Health and Safety laws**, covered under the **Work Health and Safety Act (SA) 2012** and **Work Health and Safety Regulations 2012**.

16.2

Key issues in 'capabilities to meet our challenges'

SA Power Networks is a high performing DNSP. We take pride in our strong, balanced performance over a long period of time. We have delivered on key outcomes for all our stakeholders, and have done so from a position as the most efficient distributor in the NEM. Details of 'Our track record' were provided earlier in Chapter 4.

Our Strategic Intent is to be "a leader in electricity distribution and infrastructure services in Australia", and we believe we already lead our sector in many important respects.

However, as a progressive organisation, we will continue to build and develop our capabilities to ensure we can deliver on all our regulatory obligations and meet our customers' expectations.

The 2015–20 RCP will be a period that will see the most significant and transformative change in the distribution sector since the establishment of the NEM. These changes include:

- **Technology** — digital technologies continue to proliferate in all areas of our industry and society, data volumes are rising exponentially, convergence and integration of technologies, systems and processes are accelerating, legacy systems that are unable to provide required flexibility;
- **Consumer** — everyday usage of mobile technologies is changing expectations of service providers, information access is now regarded as essential, interest in and adoption of new distributed energy resources is now mainstream, choice in energy options to help manage costs and convenience is increasingly expected;
- **Market** — new sectors have emerged around micro-generation, energy usage and demand patterns have transformed, new markets for electrical products like electric vehicles and storage are emerging, new competitive sectors are emerging (eg metering, home energy systems and energy services);
- **Regulatory** — governments are highly active in energy policy and incentive systems, regulators are pursuing competition outcomes in previous monopoly sectors, and are demanding new data requirements of monopoly sectors for oversight and benchmarking purposes; and
- **Workforce** — ageing employees will soon retire, transfer of skills to new employees is critical, new skills to support emerging service requirements are needed, and the challenge of attracting, retaining and motivating employees is growing.

Maintaining and developing South Australia's electricity distribution network in the long term interests of South Australians holds many challenges in this changing operating environment. Prior chapters of this Proposal have described key service areas for our business, and our plans for the next RCP, taking account of the concerns of stakeholders and customers. Each area involves important programs of work, underpinned by proven foundations of comprehensive governance, resources, facilities, data and systems.

The traditional competencies inferred by these foundations are still required, but we believe that DNSPs now need new competencies to survive and succeed.

In this context, our areas of focus on developing our capabilities to enable delivery of services over the coming RCP include:

1. A continuing focus on providing the right services;
2. Optimal integration of technologies and systems;
3. An integrated approach to Business Improvement;
4. An effective workforce strategy; and
5. Fit-for-purpose facilities and equipment.

16.2.1
A continuing focus on providing the right services

Future Operating Model and Strategic Plans

The Future Operating Model 2028 (**FOM**) (see Figure 16.1) represents a customer-focussed vision of our long term operating environment, including the challenges and opportunities that will most likely shape SA Power Networks over the next 15 years and beyond. It analyses new trends in government policy, technology, customer expectations, and industry regulation as well as longer term trends affecting our business.

We will update the FOM every two years as a way of having the confidence that our annual strategic plans are optimally aligned to the emerging environment and deliver a balanced and sustainable performance for our stakeholders. The insights within the FOM will help to guide our employees and decision makers over the coming years.

Figure 16.1: SA Power Networks' Future Operating Model 2013–2028

Customer engagement

'Strong customer and stakeholder relationships' are a key business driver of our Strategic Framework and are central to SA Power Networks' business philosophy. Stakeholder and customer engagement is linked into our planning processes and documents, recognising that a sustainable business strategy is one that aligns to stakeholder interests over the long term.

Recently, our reset Customer Engagement Program has helped establish a template for future engagement approaches for our business, and has been widely cited as an example for other businesses in our sector. Our preparations for this Proposal demonstrate this alignment, as we have undertaken a combination of innovative initiatives that reveal customer issues, preferences and options.

Hearing the voice of the customer, and factoring it into our objectives, strategies and services in a meaningful way, aligns with SA Power Networks' directions for the next RCP and beyond. During the 2015–20 RCP we will:

- upkeep our **Customer Service Strategy** by annual updates;
- continue our **Customer Engagement Program for future regulatory processes**, including annual pricing Proposals and future reset determinations;
- undertake ongoing stakeholder engagement programs for specific matters and issues, such as vegetation management; and
- continue our current stakeholder engagement processes for major network projects.

We expect that customer interactions will increase and become more diverse and the comprehensive nature of our engagement program will enable us to effectively listen, involve and incorporate our customers' concerns and preferences into our planning and decision processes and to enable cost-effective implementation.

Communications and information

Our Customer Engagement Program reinforced that customers already are demanding more information from the industry and from SA Power Networks in particular as one of the more trusted organisations in the South Australian energy industry. Customers are seeking information on industry roles, services and products, and are seeking advisory services on a range of energy matters. These needs will only accelerate as changes associated with metering technology, metering competition, tariff options, and new products and services take hold.

We have identified a range of communications initiatives specific to the relevant service areas, such as bushfire communications, vegetation management communications, tariff communications, and so on (refer earlier chapters). We will also provide customers additional information on general topics such as roles, services and products, and general advisory services.

16.2.2 An integrated approach to Business Improvement

Throughout 2010–15 we have maintained our focus on being a cost-efficient service provider. Our ongoing approach to challenging the way we do business has seen the development of our:

- Future Operating Model;
- Strategic Framework;
- strategy documents including our Customer Service Strategy and smarter network strategy; and
- detailed implementation plans such as the customer technology plan, our asset management plans, and our information systems options.

What has become clear is that we need to move away from the incremental change to business processes (which has occurred over many years) to a more integrated 'end state' approach to data, systems, processes and people which is linked to service outcomes and business objectives. Our business processes are spread across multiple IT systems creating hurdles to delivering business requirements and responding to customer needs.

Importantly:

- it is now imperative that we invest in the business systems to establish a strong and enduring linkage of data relating to assets, customers and work to:
  - deliver the excellence in asset management (managing an ageing and deteriorating network infrastructure which now needs to cater to two-way energy flows);
  - enable the delivery of the services that customers are expecting now and in the future; and
  - support the ongoing prudent and efficient operation of our business as described in earlier sections;
- without the proposed investment in people, data, systems and processes we will not be able to satisfactorily meet the challenges of the changing environment and provide the expected outcomes to our customers and our owners in the most cost-efficient way;
- by embracing the opportunities from digital technologies over the next few years SA Power Networks will be well placed for the long term. Without this investment there is a risk that services provided to customers will be below expectations and lag developments in other industries and across Australia;
- the skills, maturity and loyalty of our employees have been and will remain a foundation for our business success. To continue to benefit we need to invest in enhancing their skills to deal with new technologies and to provide them with the right tools, facilities and vehicles;

- over the next RCP, as we see an increasing number of our employees move towards well-earned retirement, the age and experience profile of our employees will change. Investment in recruitment and a continued emphasis on the development of our peoples' leadership and technical skills will be paramount. Ensuring that the wealth of knowledge of retiring employees is captured will be a particular focus; and
- rapidly changing technology and increase growth in data volumes means significant change to our business. SA Power Networks needs to continue to build our Business Change Management methods to appropriately respond to the changing environment. This will ensure we can respond efficiently to our customers requirements as they demand seamless experiences across multiple channels of engagement. Specifically we will align client facing and internal business processes across our organisation.

The investment in network infrastructure and customer facing developments (outlined in earlier sections) combined with the significant changes to people, data, systems and processes warrants an integrated approach to business improvement. Accordingly, we have established a framework and associated organisational arrangements to ensure the effective management of these changes and to enable Executive Management oversight commensurate with our governance framework. To this end we:

- have developed an enterprise architecture aligned to industry standards and good business practice which provides the enterprise road map for our preferred 'end state';
- have established Corporate Portfolio Management and Enterprise Architecture groups to facilitate the management of all change initiatives and to ensure they are aligned with our end state and that they are delivered as expected; and
- are progressively implementing a corporate wide approach to quality and continuous improvement which will consolidate the variety of approaches to quality currently operating in SA Power Networks.

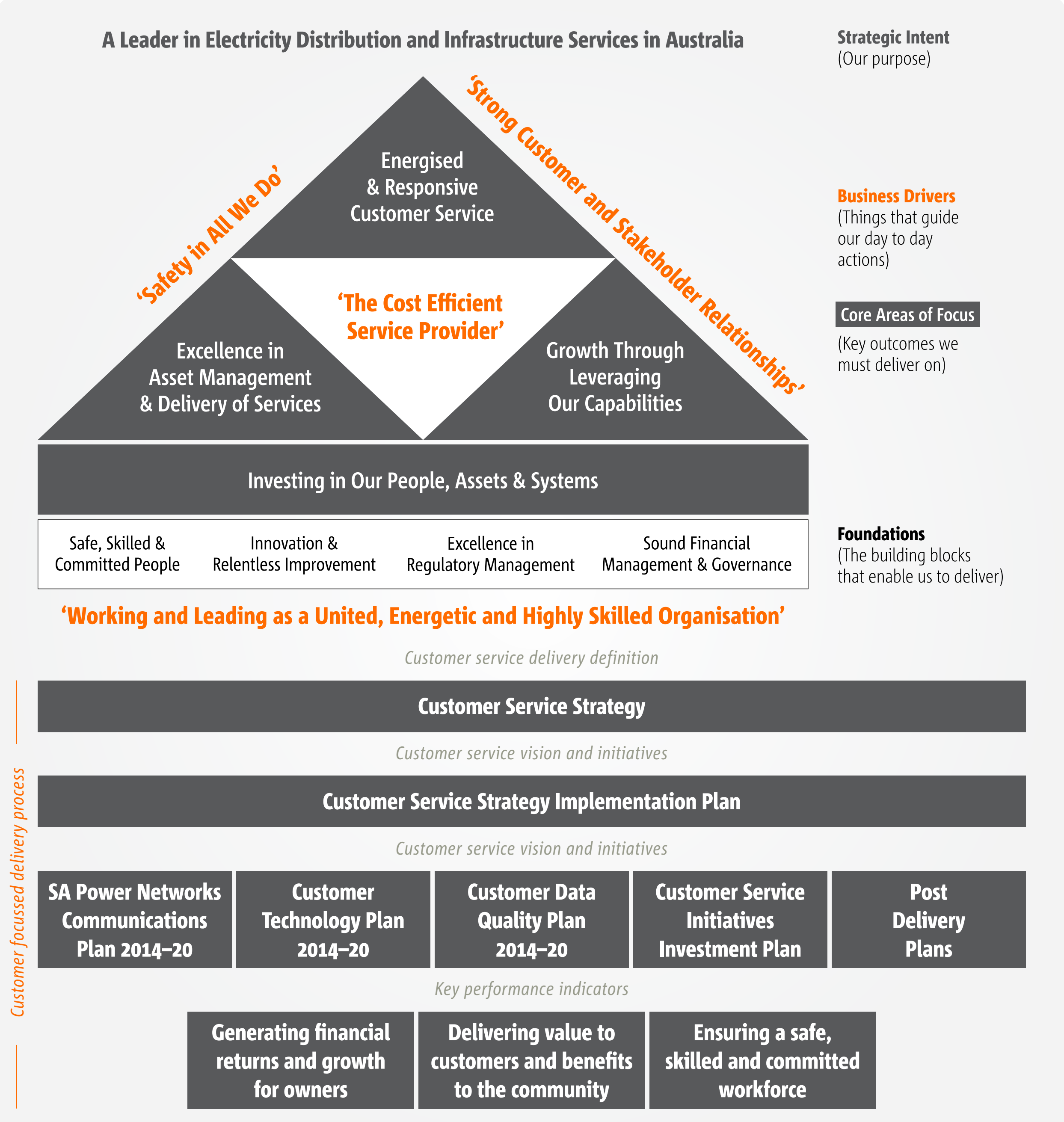
16.2.3
Optimal integration of technologies and systems

Our Proposal includes many initiatives which require investment in systems and technologies to enable delivery of the desired outcomes. A key outcome is the need for end to end integration of data to reduce duplication and manual intervention, and increase flexibility. This will provide us with a single source of information for our customers, assets, work and reporting.

Our outcomes have been defined to deliver on the directions and strategies described in the Customer Service Strategy, and detailed supporting (enabling) plans have been prepared to guide our programs (see Figure 16.2).

These supporting plans include our Customer Service Technology Plan (Attachment 14.1) and our Customer Data Quality Plan (Attachment 16.1).

Figure 16.2: SA Power Networks' customer service business model



SOURCE: SA POWER NETWORKS 2014

At the heart of both these evolving customer expectations and regulatory changes, is the need for SA Power Networks to be flexible, accurate and timely in its dealings with customers through both daily service interactions and ultimately billing practices.

As previously highlighted in Chapter 14 'Serving customers now and in the future', the current technologies in place to provide these capabilities are ageing, disparate and do not provide the flexibility required to support customer requirements, metering changes and billing solutions into the future and must be replaced. Our plan is to maintain our accurate, reliable, network billing service and position the organisation for the future. Refer to Attachment 20.32, IT Investment Plan 2014–20, and Attachment 20.37, CIS and CRM Business Case.

We have also highlighted the continued investment required in our operations systems (**SCADA & ADMS**) and our telecommunications platforms.

Regulatory requirements for data

The AER's Better Regulation program has resulted in new Regulatory Information Notice (**RIN**) data requirements from DNSPs. Benchmarking information demands are now extensive, and come with significant penalties for non-compliance. Most of the information requested by the AER is either not currently captured or not at the level of granularity being sought. To comply with AER requirements there is a need for additional data capture, management and reporting that aligns with the RIN data obligations.

To meet current year requirements the AER permitted DNSPs to estimate much of the data requested but requires DNSPs to provide actual data from 2014/15 in the case of the economic benchmarking information and from 2015/16 in the case of category analysis benchmarking information. This will necessitate investment to enable data collection, processing, maintaining and reporting across many systems. A key example will be a Financial Management project which upgrades a current standalone system to better integrate regulatory and financial information systems in support of improved reporting, analytics and decision making.

We will be working with the AER to agree a feasible time for the delivery of actual data as SA Power Networks will need to make extensive system and process investments to enable compliance with the AER's RIN requirements. SA Power Networks recognises that much of the data requested by the AER will also enhance the day to day management of our business especially if these data requirements are delivered from an integrated suite of systems.

Notwithstanding such investments, the complexity of the changes and the need to integrate data requirements across many systems and areas of the business will involve lead times which mean that SA Power Networks will not be able to achieve substantive compliance with AER RIN requirements until well into the next RCP. (Refer Attachment 20.39 RIN Business Case).

Consolidation of our information technology (IT) environment

SA Power Networks' existing systems and processes have been developed and built over many years, with a focus on meeting specific functional needs as efficiently as possible. They have not been designed or configured to capture and categorise information in the manner recently required for regulatory reporting purposes, nor have they been consistently built with end to end business processes in mind. Historically, systems have been internally developed or heavily customised with limited integration.

Rapid growth in IT systems to support business processes in the current RCP resulted in further bespoke, standalone applications in response to immediate business needs. This has added to the complexity of the IT landscape within SA Power Networks and has also driven increased maintenance and support costs. Many of these changes resulted from requirements to meet changing stakeholder expectations.

The IT application 'suite' has increased significantly from 2010 to 2013, with the majority of developments on a standalone basis. This existing technology architecture is not fit to support SA Power Networks' future directions and customer expectations.

SA Power Networks will need to significantly increase investment in initiatives that reduce our IT environment complexity and support the adoption of shared business processes, data sets and systems across the organisation. This will allow improved collaboration, business agility, error reduction and duplication and provide longer term benefits for our customers.

Rationalising the application landscape to focus on a smaller number of core product suites will provide a means of delivering the required business capability but with lower change management costs in the longer term.

Given the increase in data required to be captured and our commitment to excellence in asset management and delivery of services, a consolidated, holistic and optimal approach to the management of assets throughout their lives, from inception to decommission/replacement is required.

In response to this requirement an Enterprise Asset Management initiative (refer Attachment 20.40) has been identified to enable the improved capability. This initiative will allow SA Power Networks to achieve uplift in the way it manages the entire asset lifecycle, maximising asset productivity and ensure adherence to enterprise and regulatory procedures. This will also assist in enhancing the CBRM analysis tool implemented by EA Technologies in late 2012.

The CBRM tool provides predictive models for four priority asset classes (poles, conductors, substation switches and substation transformers). Basic data to populate the models was gathered manually from almost two dozen systems, spreadsheets and manual records sources. Asset Inspectors commenced collecting asset condition data into a third party web based tool from which it was copied to the CBRM. The process of gathering, cleaning, integrating and organising the data for import into CBRM is very labour intensive and highlighted the need for significant improvements in the available data, data quality and stronger integration between our systems to deliver CBRM models for a larger number of assets and asset classes.

In 2013, the CBRM tool became supported internally by IT, however, it is still a standalone application. Additional asset classes have been added to the models and more condition information has been collected by Asset Inspectors but the process still relies on manual cleaning and matching Asset data to build the models. In the long term this would be unsustainable due to the resource reliance with a deep understanding of the asset data structures (which takes time to develop). Having more effective integration between our systems, including with the CBRM tool, and better data quality tools will improve the quality of our long term Asset Management plans.

As SA Power Networks grows richer in data, the need for more advanced data and information handling capabilities arises. There has been a growing demand within our organisation for information management tools in recent years. In particular, we have realised that many existing business strategies are constrained without an enterprise approach to information handling. Accordingly, we plan to implement an enterprise content management tool, and this will include:

- document management (records management and digital asset management);
- document capture (scan, categorise, store and search);
- collaboration (team sites and communities, social media features and portals);
- web content management (site management, content publishing, portal management and social media features); and

- Enterprise Resource Planning (**ERP**) integration (providing visibility into the document management system from the ERP user interface, and provide a seamless and efficient user experience).

In line with increased information handling volumes, we will invest in a new Data Centre arrangement. The current business environment has demanded greater disaster recovery and an expanded hardware infrastructure to support increased system availability to underpin 24/7 service provision to our customers. Short term remedies do not provide an adequate sustainable approach. A Data Centre Strategy and Roadmap has been developed to ensure a cost effective and robust solution to support the business now and into the future, refer Attachment 16.2.

16.2.4
An effective workforce strategy

Resource planning and strategy

Implementing our long term and annual plans takes operational planning and preparation.

With one of the largest workforces in South Australia (over 2,100 employees), and high levels of workforce and resource utilisation, we must comprehensively integrate our resource planning to deliver efficiently on the work programs described in this Proposal.

This planning takes account of the projected workloads, current and forecast capacity across all our resource areas, identified gaps, and ways to close those gaps to ensure services are delivered effectively and efficiently. Integrated resource planning yields key outputs such as optimal internal versus external resourcing mix, high level implementation schedules, and cost estimates.

Through this process, we have identified that, with the anticipated workload profile over the 2015–20 RCP, we will need to increase both the numbers of contractors and our internal capability.

To maintain our standards we will make adequate provision for administrative, managerial and support resources to manage higher volumes of sub-contracted work.

To enable the efficient management of our resource planning we will be linking our resource management systems and our work planning and qualification systems to ensure full utilisation of our resource pool.

Workforce and skills development

The electricity industry has one of the oldest workforces of all Australian industries, with close to half of workers aged 45 and over. Also, the post-Global Financial Crisis (**GFC**) environment has caused many workers to delay retirement. For example, in any typical year before the GFC, the number of our workers in the age range of 60–69 years would be around 155, but by April 2014 this number was 216.

Given that the industry is technically specialised with an inherently high risk work environment, it takes considerable time and effort to train and develop new workers and apprentices. At some point in the next few years, our cohort of older workers will move to retirement and will need to be replaced. This will be a significant challenge in transitioning and replacing an ageing workforce.

We have well-developed capabilities in terms of workforce renewal. For example, over the last six years, we have seen 231 apprentices commence with SA Power Networks, and we have recorded a retention rate of over 90% upon completion of apprenticeships. These capabilities will be crucial in renewing our field resources during the next RCP.

The technical skills profile for this industry, as described in our FOM, also means that we will need new and more complex competencies among our broader workforce. Clearly then, the coming period will be a period of renewal for our people as well as our assets, and we must transfer knowledge and skills to the next generation of employees. Our plans must provide for:

- increased capacity of our internal field workforce, in terms of field maintenance, construction and design roles;
- the need to develop the optimal skills profile of both our field and office based roles, considering the technological and other changes underway in our sector;
- systematic approaches to knowledge and skills retention and transfer; and
- centralised system to effectively manage our skills and training.

Workplace safety

In our industry, we are recognised leaders in terms of organisational capabilities and achievements in workplace safety. This is achieved by the ongoing dedication of our employees and leaders to ensure all work is performed safely so that our employees go home injury free.

Our workplace safety is governed by our Work Health and Safety Policy and Directive which are both aligned with the Nationally Harmonised Work Health and Safety Legislation and more recently Federal Safety Commissioner Standards. Significant management and employee time and effort is focused on workplace safety.

Requirements arising from workplace safety legislation changes are continually factored into SA Power Networks' strategies and plans, to help ensure that SA Power Networks remains at the forefront of workplace safety. Appropriate workplace safety enhancements are incorporated in our Proposal for the next RCP.

16.2.5
Fit-for-purpose facilities and equipment to support our people

Renewing our workforce, and building the resources to deliver the work programs discussed in earlier sections will require new investment. We will need to continue to provide the workforce with modern and safe property, equipment, vehicle fleet support and other logistical infrastructure, such as IT systems.

IT and Communications Systems

Mobility platform and solutions — In the current period we have expanded our mobility platform to increase the scope of the field functions and processes covered. Notwithstanding this, there remains a significant number of manual and paper based processes which result in multiple handling of data and relies on a range of mobile solutions with our people using multiple devices while undertaking day to day operational activities. There is a clear need for an integrated mobility solution which leverages current digital technologies and covers all aspects of field and customer related work.

This will address some of the challenges facing our crews by enabling them to operate more efficiently and effectively when building and maintaining the distribution network. We aim to provide our crews the ability to flexibly manage, execute, monitor and analyse work in the field via mobile devices, tablets, wireless networks and related services.

In recent years, field force mobility solutions and technologies have become more pervasive, better understood and cost effective. In summary, we will continue to build our mobile capabilities by improving our data and voice networks to enable our people to efficiently capture, view and share accurate information when they need it, wherever they may be, with a single (type-agnostic) device on a secure technology platform (refer Enterprise Mobility Strategy Attachment 20.49 and IT Field Force Mobility Business Case Attachment 20.48).

Portfolio Project Management (**PPM**) — We have a solid foundation of project management capabilities within SA Power Networks. As part of the approach to have business-wide integrated processes and systems we are embarking on implementing an integrated project, program and portfolio management system. This will also include a project scheduling and resource capacity system and will leverage our existing corporate Enterprise Resource Planning system (**ERP**) which will enable SA Power Networks to identify and manage the most appropriate work to perform as work volumes increase. The PPM Business Case can be found at Attachment 20.47.

Property

Property facilities are a foundation of our field and office based operations, for example our FOM includes future directions for some of our property types. Optimal property facilities assist in the delivery of efficient, reliable and safe business performance.

Our property refurbishment program encompasses staged upgrades and rebuilds to many of our dispersed property facilities across the State. This approach is based on a comprehensive review of location, functionality, compliance and condition of each property. This, coupled with the forecast growth in resources required to deliver our program of work has identified the need for significant investment. Ensuring a safe environment including vehicles movements at our depots is paramount.

A continuing challenge for our business is that some of our property locations within Adelaide's greater metropolitan area are becoming increasingly distant from major growth areas. This means there is non-productive time spent travelling to and from our depots in the ongoing delivery of our work program and during emergency response activities accentuated by increasing traffic congestion on South Australian roads. Our Future Depot Locations report evaluates optimal siting of our operational facilities to maintain service outcomes for customers. The benefits of reducing travel times has been factored into our resourcing requirements for 2015–20.

SA Power Networks regularly reviews the appropriate number, location, type and size of property facilities to support effective and efficient delivery of services to customers. In the next RCP, our key investments will include:

- new Seaford depot (build and fit-out);
- Angle Park North and Marleston North (relocation of functions and reconfiguration of existing sites);
- Keswick head office (ongoing refurbishment);
- new Nuriootpa depot (land acquisition and new depot construction); and
- Clare and Kadina (build and fit-out of expanded depots).

Further detailed information on these initiatives can be found in Chapter 20 and in the Strategic Property Plan Attachment 16.7.

Fleet

Employee safety is paramount to SA Power Networks. Our vehicle fleet team has a key role in ensuring the supply of fit-for-purpose, safe and legislatively compliant vehicles to the business in a timely manner. We have a detailed replacement plan for heavy and light vehicles and associated facilities including proposed changes to our replacement policy to align with current industry practice.

As previously highlighted, SA Power Networks needs to significantly enhance mobile capabilities; this requires our fleet vehicles to feature significantly more on-board computing capability and technology, which will facilitate access to real-time asset information.

Further detailed information on these initiatives can be found in Chapter 20 and in the Strategic Fleet Plan Attachment 20.26.

Supply Chain

SA Power Networks recognises the advantages of effective and efficient supply chain capabilities. We have had significant capability uplift in our supply chain processes during the current RCP which has enabled us to achieve savings in our supply chain as reflected in lower capital expenditure for activities undertaken in this period. As we continue to strive to meet our Supply Chain Strategy 2020 vision, we will build on our foundations and focus on several new key technology developments:

- information system interconnection to support more effective management of suppliers;
- supply chain performance analytics; and
- materials planning and management system including business-to-business (B2B) transactions.

This is expected to significantly improve our supply chain capabilities in terms of better inventory visibility, faster response to materials delivery to work sites, and better planning and support for major service events (refer Attachment 16.5).

16.3

What our stakeholders and customers have said to us, and our response

16.3.1
Understanding our customers' concerns

During the Research Phase of our TalkingPower consultation program we provided some relevant information on key topics and asked our customers and key stakeholders what they expected from SA Power Networks over the next five years and beyond. This was done in the context that any investments and operating costs would be managed within no more than a CPI increase in their network charges. Specifically, with respect to 'capabilities to meet our challenges', our TalkingPower Customer Engagement Program confirmed that:

- **engagement capability** — in workshops at stage 1 of our Customer Engagement Program, 92% of participants agreed or strongly agreed the workshop met their expectations and 94% would like to see further workshops run in the same fashion;
- **engagement capability** — in workshops at stage 2 of our Customer Engagement Program, 97% of participants indicated they would like to see further workshops run in the same fashion;
- **communication capability** — customers have new expectations about how and when we communicate with them and they want more information about the electricity industry;
- **communication capability** — we should educate customers about new technology and industry change to help increase their satisfaction to enable them to make informed decisions about their energy use;
- **customer service capability** — we should maximise opportunities to improve service experience, including by developing multi-channel communication strategies;
- **customer service capability** — 61% of customers surveyed said we should be proactive and responsive, and continue to improve our interactions with them; and
- **resources capabilities** — we should continue to invest in facilities, staff, fleet and technology to ensure timely restoration of supply across South Australia.

16.3.2
Integrating customer feedback into our business planning process

These customer insights were fed into our planning for the next RCP and a range of key investment options were communicated back to customers and stakeholders for confirmation and comment. These investment priorities were then more broadly consulted on in our 'Directions and Priorities 2015 to 2020' consultation document.
The investments included:

- invest in continuous improvement of our governance programs;
- maintain advanced stakeholder engagement and long term planning to ensure we keep abreast of expectations, requirements and technological and market developments;
- drive our systems and culture to support great customer service and outcomes;
- refining our integrated resource planning capabilities to deliver on our work programs;
- continue investing in modern and safe standards of property, technology and systems, equipment and vehicles to deliver the work programs; and
- invest in the IT systems and capabilities we need to deal with a step change in operational complexity associated with advanced metering, billing requirements, new regulatory reporting and service requirements, customer service expectations, workforce mobility, and advanced asset management capabilities.

16.3.3
Feedback received on our 'Directions and Priorities 2015 to 2020' consultation document

Responses to the Directions and Priorities document with respect to 'capabilities to meet our challenges' were:

Business SA submission:

- "We note that SAPN's workforce has grown by over 90% since 1999. By comparison, South Australia's population in 1999 was 1.495 million and today stands at 1.674 million, an increase of 12%.
- "We encourage SAPN's strong focus on training apprentices and acknowledge that it is necessary to ensure the older cohort of technical staff can be adequately replaced in coming years. However, we are concerned about any significant rise in costs, whether it be for labour or otherwise, which are ultimately borne by consumers, including small businesses."
- "Business, particularly small business, have become accustomed to doing more with less over the past several years in response to trying economic circumstances. This drive in productivity has been necessary just to remain viable and we encourage SAPN to focus on productivity across its operations."

Minister for Mineral Resources and Energy submission:

- "It is pleasing to see that community consultation has occurred in establishing the Directions and Priorities for SA Power Networks."

Central Irrigation Trust (CIT) submission:

- "We believe that the consultation process is flawed and biased and influences the outcomes of the consultation towards the SA Power Network(s) view … CIT do not accept the results of the surveys and any conclusions drawn from it."

16.4

SA Power Networks' response to consultation, and proposed expenditures

The majority of Directions and Priorities consultation feedback focussed on work program proposals and overall pricing outcomes, and touched on specific capabilities-related issues in limited ways. However, with regard to Business SA's comment on workforce growth, we point out that SA Power Networks' workforce has grown in proportion to the significant work program approved at the last regulatory determination for the 2010–15 RCP.

However, one exception was CIT, which addressed the approach of the Customer Engagement Program, and by implication the associated engagement capability as described in this chapter. CIT was strongly of the view that the Customer Engagement Program was flawed and biased. This is contrary to the reviews expressed by the overwhelming majority of participants in the stage 1, stage 2 and targeted strategic workshop phases of the program who were indeed highly satisfied with the approach and conduct of the workshops. The program was carefully designed in accordance with recognised principles and proven approaches, as reinforced by expert advice from a range of engagement practitioners. Chapter 6 and Attachment 16.6 to this Proposal, as well as the TalkingPower website, provide extensive details on the approach and outcomes of the Customer Engagement Program.

In summary, our proposed program to ensure appropriate 'capabilities to meet our challenges' includes initiatives and projects that:

- maintain our industry-leading approaches to long term service provision, including through our corporate governance processes and maintenance of our Future Operating Model;
- further develop and embed our stakeholder and customer engagement systems and processes;
  - additional service quality management research processes; and
  - increased stakeholder and customer enquiry management resources to cater for current and forecast demand trends, in line with a more complex operating environment;
- address customer preferences through the provision of additional educational information to customers on various industry topics and energy advisory areas;
- improve the integration of technologies and systems to enable delivery of our services to the required standard in all areas:
  - consolidation of our complex IT architecture and application landscape;
  - replacing our legacy systems to allow flexibility and improved billing capabilities;
  - investing in capturing, maintaining and integrating our business data, information and business processes;
  - optimising our mobility platform and increasing mobile capability to our field crews; and
  - maintaining our core IT capabilities through orderly refreshes of infrastructure, operating systems and business applications;
- support SA Power Networks' integrated Business Improvement capabilities in an increasingly changing, demanding, interconnected and complex operating environment:
  - development of Corporate Portfolio Management and Enterprise Architecture management capabilities that facilitate the efficient and effective oversight of all change initiatives; and
  - development and consolidation of corporate-wide quality management systems and workplace processes and systems that drive continuous improvement outcomes;
- execute our workforce strategy in order to deliver safely and efficiently on the work programs described in this Proposal:
  - continuation of an optimised mix of internal and externally-sourced resources;
  - bolster our internal field resource base by recruitment of an additional (approximately) 90 Trade Skilled Workers (**TSWs**) over the next RCP, and maintain our significant Apprentice intake program;
  - implement specialised training programs for TSW and Apprentice resources, using our well-established facilities and training systems;
  - reinforce our external resourcing capability by working with existing contractor 'panel' service providers, and exploiting growing availability of interstate resources as appropriate;
  - provide for increased supervision and contractor management capabilities that will be needed to support higher volumes of sub-contracted work;
  - continue to identify, establish and maintain appropriate skills profiles of both our field and office based roles, considering the technological and other changes underway in our sector;
  - implement processes and systems that systematically support knowledge and skills retention and transfer in an environment of workforce renewal; and
  - maintain our benchmark safe workplace, making provision for new requirements as appropriate:
    - upgrade our contractor induction and safety management capabilities;
    - expand our vehicle inspection programs to comply with regulated requirements, noting that SA Power Networks operates one of the largest heavy vehicle fleets in the State; and
    - introduce technology and systems that will address safety risks for our people in the field. Our field workforce is highly mobile, and our people spend a significant amount of time on the State road system, frequently operating alone or in remote locations. A range of improved approaches will be introduced;
    - property and equipment:
      - implement our Strategic Property Plan 2015–20;
      - have an appropriate number of depots and office locations based on services requirements for customers; and
      - supply of fit-for-purpose, safe and legislatively compliant vehicles.

Table 16.1 outlines the key capital expenditures proposed for the 2015–20 RCP and Table 16.2 details changes to operating costs above the efficient base year. Further detail on specific capital and operating items can be found in the referenced sections of this Proposal.

Table 16.1: Capabilities to meet our challenges — capital expenditures

Item	2015–20 RCP 2015$	Reference section
Information Systems and Technology		
RIN Reporting	15.0	20.8.1
Financial Management	7.9	20.8.1
Intelligent Design Management System (IDMS)	9.2	20.8.1
Enterprise Asset Management	31.4	20.8.1
Data Centre Consolidation	4.3	20.8.1
Portfolio Project Management	4.0	20.8.1
Supply Chain Capabilities	4.2	20.8.1
Enterprise Integration Layer Project	6.6	20.8.1
Data Management	2.7	20.8.1
Enterprise Information Management	7.4	20.8.1
Enterprise Enabling Technologies	18.7	20.8.1
Other Business Solutions	5.1	20.8.1
IT Management Capabilities	6.6	20.8.1
Client Devices	19.7	20.8.1
Technical Operations	25.0	20.8.1
Application Upgrades	43.5	20.8.1
Nation Market Systems (CHED)	11.0	20.8.1
Business System Upgrades	21.0	20.8.1
Management, Risk, Compliance and Governance of IT	5.6	20.8.1
Advanced Distribution Management System (ADMS)	11.1	20.8.2
Telecommunications Network Operations Centre (TNOC)	9.0	20.8.2
Emergency Services	5.4	20.8.2
Land costs	1.1	20.8.3
Buildings	107.3	20.8.3
Easements	3.2	20.8.3
Fleet (Vehicles and Safety)	146.0	20.8.4
Plant and Tools	26.7	20.8.5
Capex Total	**$558.7m**	

Table 16.2: Capabilities to meet our challenges — operating step changes expenditures

Item	2015–20 RCP 2015$	Reference section
Technology and systems — licensing, maintenance and support	43.9	21.6.2
Network Telecommunications Enhancements	8.7	21.6.2
Technology, Business and Systems — RIN requirements	9.2	21.6.1
Legal/Reg — Change in planned outages notification time	4.3	21.6.1
Safety — Fleet Inspectors	3.9	21.6.1
Safety — IVMS monitoring	2.2	21.6.1
Legal — Environmental Management Resources	1.4	21.6.1
Insurance Premiums	3.0	21.6.4
Opex Total	**$76.6m**	

16.5

Benefits to customers

These Proposals will provide the following benefits to South Australian customers:

Alignment

- SA Power Networks will be better placed to both deliver on regulated obligations and meet our customers' expectations;
- alignment of the long term interests of South Australians with the assets, services and performance associated with South Australia's electricity distribution network will be improved; and
- the 'voice of our customers', in terms of their needs, concerns and preferences, will be central to our objectives, strategies and programs.

Services and engagement

- SA Power Networks' focus on strong customer and stakeholder relationships will be enhanced;
- stakeholder engagement processes for major network projects will be improved; and
- customer service outcomes will be enhanced in general.

Information

- customers will receive the improved information on industry roles, services and products, and advisory services that they have sought throughout our Customer Engagement Program;
- improved asset, process, project and program management;
- the AER will receive more accurate information for benchmarking purposes, improving their oversight of regulated services; and
- we will leverage this information in our day to day operations.

Performance

- SA Power Networks' performance in terms of both efficiency and service provision to customers will be enhanced by:
  - better asset management capabilities;
  - enhanced quality management capabilities;
  - better program coordination;
  - optimal use of digital technologies; and
  - embedded continuous improvement capabilities.
- work programs will be efficiently and safely delivered by:
  - an optimal resourcing strategy, making the best use of internal and external contracting resources;
  - ongoing best practice safety practices applied for all our resources; and
  - ensuring that the wealth of knowledge of retiring employees is captured and applied by the organisation.

17
Service-price trade-off

17

Key points

- The 'regulatory bargain' aims for a balance between the objectives of customers and the interests of SA Power Networks, which should be able to receive a reasonable commercial return in providing services to customers at an agreed standard.

- Chapter 6 of the National Electricity Rules (**NER**) guides the approach to setting a reasonable return for a distribution business. The National Electricity Objective (**NEO**) reflects the high level outcomes customers should expect to receive.

- In practice, the Service Standard Framework (**SSF**) that applies to SA Power Networks mandates the service levels that underpin NEO outcomes. ESCoSA sets the SSF. The SSF remains substantively based on the legal requirements under the Electricity Act and ESCoSA's ground-breaking 2002 survey that established customers' Willingness to Pay for key network services. ESCoSA's practice has been to revalidate the Willingness to Pay research every five years, before the commencement of the next RCP.

- Whilst reliability is very important, customers place significant value on many other services. SA Power Networks conducted extensive 'service value' research in 2012 that established that customers appropriately expect us to deliver a diverse range of services. The service-price trade-off is much more complex than just a reliability-price tradeoff.

- Infrastructure (expansion, safety, and appearance) and bushfire (risk) management were the most valued lines of service provided by SA Power Networks. Reliability was further down the list of priorities for the respondents to the survey.

- The design of our Customer Engagement Program was informed by this service value research. Our Customer Engagement Program covered (i) historical, current and emerging services, (ii) short term and long term services, and (iii) direct (eg keeping the power on) and indirect (eg safety for the community) services.

- All of these service dimensions are part of the service-price trade-off. Our Customer Engagement Program was framed against a basket of services that could be delivered for an indicative price outcome to South Australian customers. In turn, participants in our Customer Engagement Program readily understood and expressed support for our wide range of services.

- In our Customer Engagement Program, advanced collaborative engagement techniques were also used to explore selected topics. 'Design thinking' was used to develop vegetation management and community safety solutions that were further developed and tested in advanced discrete choice modelling Willingness to Pay research. Based on the findings of the Willingness to Pay work, modest customer-supported programs have been incorporated in our Proposal.

- We consider this Proposal represents an appropriate balance of price and service that will meet the needs of South Australian customers and the wider community, and position us for sustained service delivery into the long term.

17.1

The 'regulatory bargain' — a reasonable return for provision of services to a standard

Operation of electricity network infrastructure is considered to be a natural monopoly activity. Consequently, SA Power Networks operates under comprehensive service, technical and economic regulation to ensure that key service levels are maintained and that efficient prices are levied on customers.

The term 'regulatory bargain' has been used to describe the nature of the outcomes arising from these arrangements, for customers and the regulated entity, in this case SA Power Networks. The regulatory bargain aims for a balance between the objectives of customers and the interests of the Distribution Network Service Provider (**DNSP**) business, such that SA Power Networks receives a reasonable commercial return for the provision of specified services to customers at an agreed standard.

The National Electricity Objective (**NEO**) reflects the high level outcomes customers should expect to receive, and is central to justifications of DNSPs' regulatory Proposals. Chapter 6 of the National Electricity Rules (**NER**) specifies the approach DNSPs must take to making regulatory Proposals, and also sets the parameters that determine a reasonable return to a DNSP.

In practice, the jurisdictional Service Standard Framework (**SSF**) that applies to a DNSP mandates the service levels that underpin key NEO outcomes.

In South Australia, under the Australian Energy Market Agreement, ESCoSA has responsibility for setting the SSF. The SSF for the 2015–20 RCP has been determined by ESCoSA.

SSF standards and targets are embedded within the Electricity Distribution Code (**EDC**), and compliance with the EDC is a requirement of SA Power Networks' licence. Consequently, performance in accordance with the SSF is mandatory for SA Power Networks.

The SSF covers reliability service standards and targets, customer service standards and targets, and Guaranteed Service Levels and payments. These have been discussed in earlier chapters of this Regulatory Proposal.

The SSF remains substantively based on legal requirements under the Electricity Act and ESCoSA's ground-breaking 2002 survey[48] that established customers' Willingness to Pay for key network services. ESCoSA's practice has been to revalidate the Willingness to Pay research every five years, before the commencement of the next RCP.

17.2

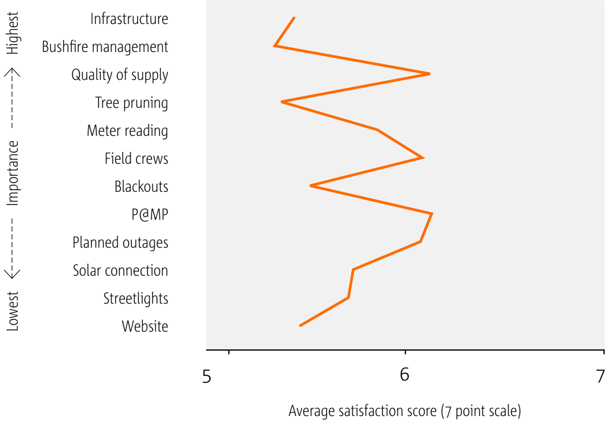
Understanding what customers value

It is sometimes suggested that reliability service levels and targets, such as those embedded within our mandated SSF, are the primary customer outcome under the NEO, and that customers' Willingness to Pay for them is central to evaluating the appropriateness of the regulatory bargain. That is, it is argued that understanding customers' reliability-price 'value equation', or trade-off, is most important.

SA Power Networks' proprietary research demonstrates that customers value more than simply reliability. We conducted 'service value' research, (refer Attachment 6.1 — SA Power Networks Customer Management Model Study — regulatory summary, ORC International) in 2012 that established that while reliability outcomes are certainly very important to customers, customers' personal value equations (trade-offs) are much more complex than some commentators believe.

Our 2012 service value research confirms that customers value a collection of services and outcomes, some more highly than SSF reliability outcomes. For example, it demonstrated that 'infrastructure' (eg including expansion, safety, and appearance attributes) and'bushfire management' (eg including network maintenance, inspections, design, vegetation management, and communications attributes) were the most valued 'service arenas' provided by SA Power Networks. Reliability (ie the 'blackout' service arena) was further down the list of priorities for the respondents to the survey (see Figure 17.1).

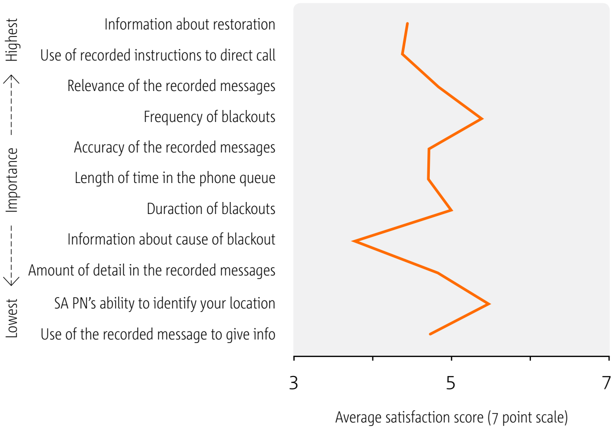
Figure 17.1: Overall importance and performance of service arenas



At the service arena level, the research provided even deeper insight into attributes, their importance and SA Power Networks' perceived performance against them. With regard to 'blackouts', it can be seen in Figure 17.2 that three different outage information attributes were rated higher than the fourth-rated physical outage attribute (ie the 'frequency of blackouts' attribute).

48 KPMG, Consumer Preferences for Electricity Service Standards, September 2003

Figure 17.2: Blackouts satisfaction and importance



This is an important insight. Our customers value much more than reliability alone, and indeed place very high value on a wide range of service arenas and attributes. To over-emphasise the SSF reliability-price trade-off is to ignore these other diverse sources of customer value.

As discussed in Chapter 14, 'Serving customers now and in the future', there are now even more emerging service arenas than covered in our 2012 research. It is highly likely that the 'basket' of services valued by our customers will expand even more over time.

17.3

Impacts on the design of our Customer Engagement Program

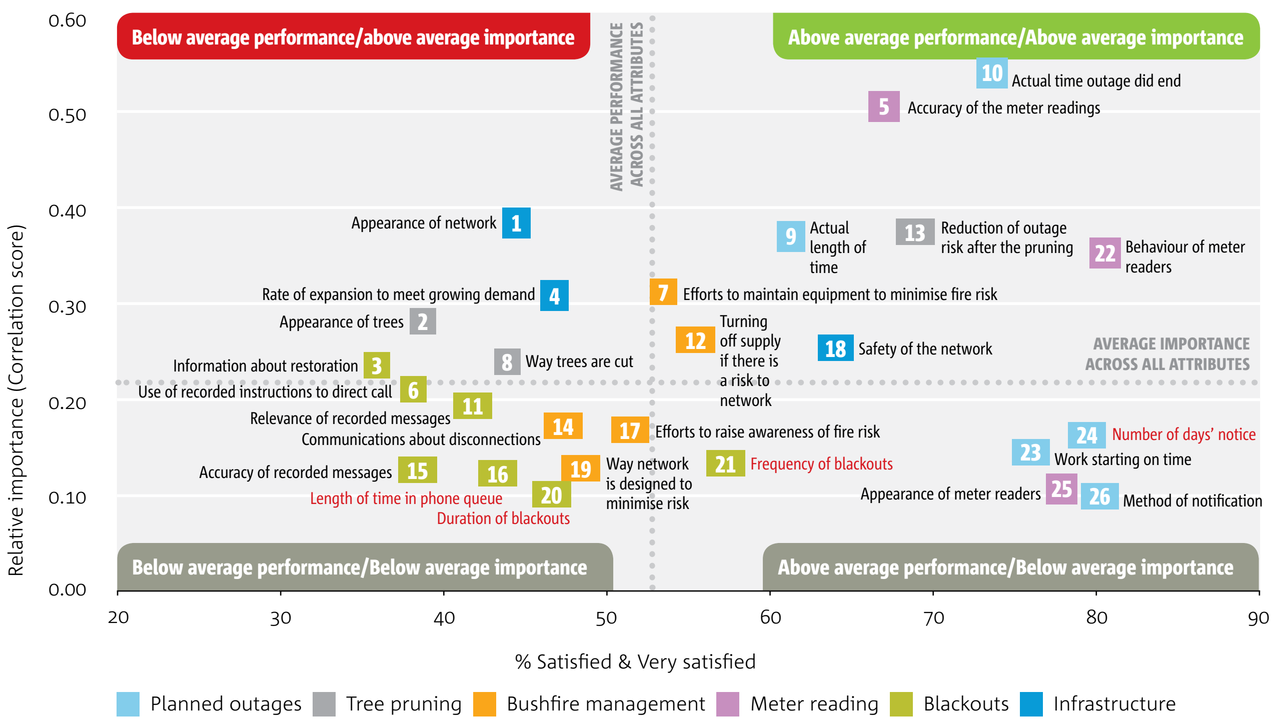
17.3.1
Engagement topics reflected service value — nowand emerging

As discussed in Chapter 6 and in Attachment 16.6, our Customer Engagement Program was designed to ensure that a comprehensive and appropriate range of service arenas and attributes formed the basis of our engagement.

The program design was partly informed by our 2012 service value research which provided important indicators of key candidate topics for the Customer Engagement Program.

The quadrant analysis shown in Figure 17.3 suggested that priority should be assigned to service arena attributes that customers perceived to be of above-average importance and which suffered below-average performance by SA Power Networks. This analysis helped inform the initial Customer Engagement Program topic design.

Figure 17.3: Prioritising Customer Engagement Program engagement topics — service value research quadrant analysis



The program also took account of the range of regulatory, market and technological changes that are driving emergence of new sources of value for customers that are relevant for the longer term.

Thus, the program incorporated an 'evolving customer' theme, where emerging service value issues were explored. The recent AEMC Power of Choice review provided important context to these discussions with customers.

17.3.2 An appropriate pricing context for the Customer Engagement Program

All program workshop discussions, the online survey, and the 'Directions and Priorities 2015 to 2020' consultation process adopted the explicit context of an indicative and easily understood distribution price path.

Although minor variations on the pricing context were reflected at various stages of the program (taking account of the best information available at a given point in time), the general pricing context was that the basket of services would be delivered with annual network price changes limited to no more than CPI. This was critical if customers were to be able to come to a personal judgement of value and balance with regard to mooted directions and priorities.

17.3.3 Customer Engagement Program explored the value of a basket of services at the indicative price

Our program was consistently framed around a comprehensive basket of services that could be delivered for an indicative price outcome for South Australian customers. The program service-price trade-off therefore covered:

(i) historical, current and emerging services;
(ii) short term and long term services; and
(iii) direct (eg 'keeping the power on') and indirect (eg 'safety for the community') services.

SA Power Networks considers that this results in a more realistic and meaningful service-price trade-off, as opposed to a simpler reliability-price trade-off.

Focussing on reliability alone would have been inappropriate in the context of our 2012 service value research, and the ongoing emergence of new sources of customer value.

In turn, participants in our program readily understood and expressed support for our wide range of services, validating the proposition that the service-price trade-off is complex and multi-faceted.

17.4 Extending investigation of the service-price trade-off

In developing our expenditure proposals, SA Power Networks sought to address the concerns of electricity customers as identified in the course of our engagement with them. Under NER 6.5.6 (e) (5A) and NER 6.5.7 (e) (5A) the AER must have regard to the extent to which the expenditure forecasts include expenditure to address the concerns of electricity consumers identified in the course of our engagement with electricity consumers.

Stage One of our Customer Engagement Program identified a number of issues of concern to customers that warranted further investigation. In particular, strong signals emerged from our engagement that indicated customers wanted SA Power Networks to do more in the areas of vegetation management and undergrounding. These signals were not surprising, considering the history of community comment and debate in our State with regard to these matters.

As discussed in Chapter 6, Chapter 11 and Chapter 15, Stage Two of our program went even further in exploring the extent of customers' service-price trade-offs in these specific areas, making use of advanced stakeholder engagement processes to explore the two topics further.

Expert independent facilitators who were skilled at promoting 'design thinking' led Targeted Strategic Workshops. At these workshops, stakeholders, subject experts and company staff collaborated to review issues and agree on balanced options and appropriate criteria that would meet the needs of the community.

The outputs of these workshops were further developed into concept options, with accompanying cost estimates, by staff teams using the business' detailed knowledge and information sources.

The next step was to translate these concepts into Willingness to Pay survey instruments, before running discrete choice modelling research to develop statistically valid Willingness to Pay results. We also took steps to ensure 'hardship' customers were properly addressed in the research, as this segment is particularly difficult to reach with common research approaches.

Based on the findings of the Willingness to Pay work, which demonstrated strong support for a number of collaboratively-developed programs, modest customer-supported initiatives derived from Customer Engagement Program insights were incorporated into our 'Directions and Priorities 2015 to 2020' consultation document and process (Note that the Willingness to Pay results actually indicated that customers were willing to pay for significantly larger capital and operating programs, up to $605m total expenditure, compared to the $260m total expenditure program actually included in the Directions and Priorities initiatives).

These customer-requested initiatives, and their costs, were identified in the consultation document. The document also detailed the total capital and operating expenditure proposed for 2015–20 and the likely impact on network charges over this period.

In consideration of feedback through our 'Directions and Priorities 2015 to 2020' consultation process, we further reduced the extent of these customer-requested initiatives.

In this Proposal, as detailed in earlier chapters, we have included capital expenditure of $206.1 million and additional operating expenditure of $36.4 million for investments to deliver:

- targeted undergrounding to ensure reliable power to some CFS Bushfire Safer Places and in high priority bushfire risk areas;

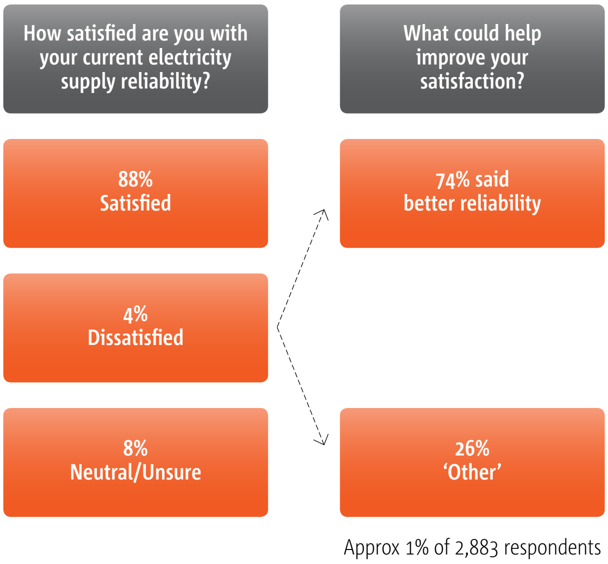
- improvements in the way trees are managed around power lines;
- undergrounding of some power lines to improve road safety; and
- safety campaigns relating to bushfire and severe weather events.

17.5

Stakeholder views on reliability-price trade-offs

Our Customer Engagement Program examined satisfaction with current levels of reliability. 88% of online survey respondents were satisfied. Of the 4% who were unsatisfied, 74% wanted more reliability, leaving a very small number (about 1% of respondents) for whom it is unclear how their satisfaction might be increased (see Figure 17.4). So, there appears to be a very significant bias among South Australian customers towards current or improved levels of reliability.

Figure 17.4: Customer Engagement Program online survey — satisfaction with current reliability



Most South Australian stakeholders and customers, and indeed the service regulator, ESCoSA, as evidenced by its SSF decision in May 2014, consider that it is appropriate that SA Power Networks should work to maintain service levels, including reliability. Obviously, this outcome must be achieved in the most prudent and efficient manner.

Nevertheless, varying views among stakeholders on service or reliability trade-offs do exist.

Business SA:
In its submission to SA Power Networks' 'Directions and Priorities 2015 to 2020' consultation, Business SA commented SA Power Networks "is doing a solid job of ensuring electricity distribution in South Australia is reliable, even amongst what are often very trying circumstances … it is critical that the focus on electricity reliability across the State be maintained as a foundation for economic growth."

In Business SA's March Quarter 2014 Survey of Business Expectations, participants were asked about reliability during peak demand periods. Of the businesses surveyed, 82.1% were satisfied with the level of electricity reliability provided by SA Power Networks during the last summer heat wave. In the same survey, when asked if they would consider a lower level of electricity reliability if it came at a reduced cost, a significant majority of respondents (73.2%) said no.

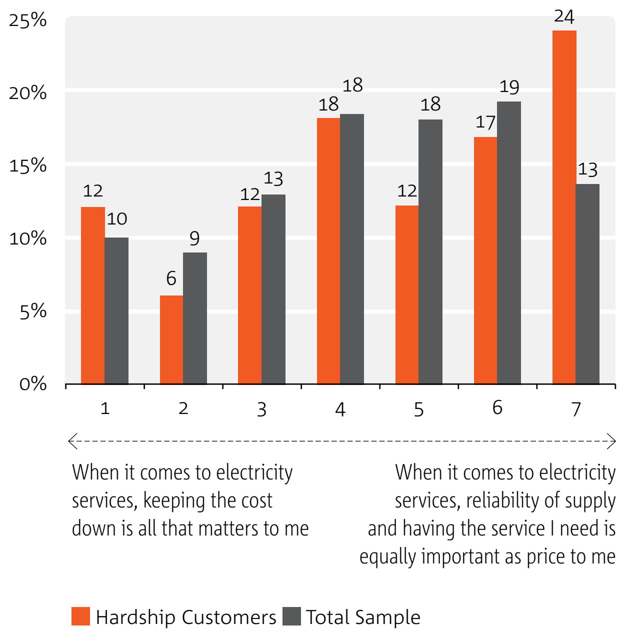
Consumer Challenge Panels:
Recently, the AER's Consumer Challenge Panels (**CCP**) have argued that some DNSPs' statements that customers wish to maintain current levels of reliability are flawed. They cite anecdotal evidence that consumers may prefer lower prices even if that meant a greater risk of reduced reliability. They also believe that consumers have not been asked 'the key questions' about how much risk they were prepared to take for different levels of reliability[49]. This is argued to especially be the case for a 'large cohort' of consumers who are very price sensitive (hardship customers).

SA Power Networks' Willingness to Pay surveys described in 17.4 above included a survey of the attitudes of hardship customers. 30 in-depth interviews were conducted in the week commencing 28 April 2014. The purpose of these in-depth interviews was to better understand the attitudes and motivations of hardship customers with respect to their decisions.

In stark contrast to CCP assertions, hardship customers' attitudes to key reliability-price trade-off matters seem not to differ significantly to those of the general population.

Hardship customers were more likely (24% vs 13% total Willingness to Pay sample) to completely agree that the reliability of electricity supply is equally important as cost. This shows that a significant proportion of the community value reliability of supply over the cost (Figure 17.5).

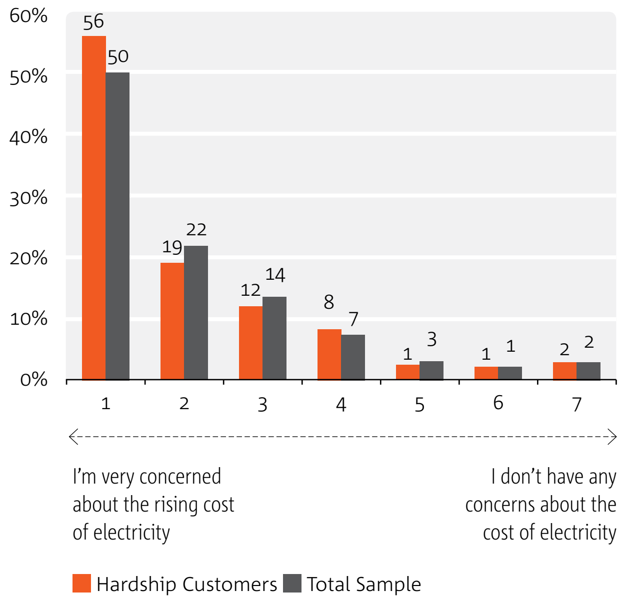
Figure 17.5: Hardship customers — importance of cost versus reliability



49 CCP1, Jam Tomorrow? (submission to AER regarding NSW DNSP regulatory proposals 2014–19), August 2014

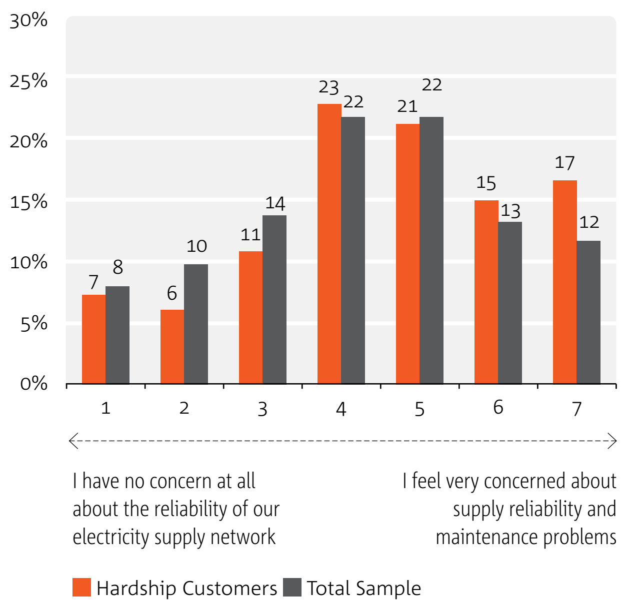
Hardship customers were only slightly more likely to indicate that they were very concerned (56% vs 50% total Willingness to Pay sample) about the rising cost of electricity (see Figure 17.6).

Figure 17.6: Hardship customers — concern for electricity cost increases



Finally, hardship customers were more likely to indicate that they were concerned (32% vs 25% total Willingness to Pay sample) about reliability of supply. This concern reflected a broader concern for public infrastructure (eg public transport, hospitals), based on their reliance upon these public services. (Figure 17.7).

Figure 17.7: Hardship customers — concern about reliability of supply



SA Power Networks has also undertaken a survey of a representative sample of 760 South Australian customers, as described in Attachment 17.3 — The NTF Group, Service-Price Research Findings. The results are shown in Figure 17.8.

Figure 17.8: Reliability-price preferences of South Australians

These results, taken with the recent hardship customer survey and our online survey results, indicate that CCP views regarding a large cohort of customers who are likely to prefer reduced reliability in return for reduced price are questionable.

17.6

The service-price trade-off, and our value proposition

This Proposal has been developed on the foundation of a transparent, robust, progressive and extensive Customer Engagement Program. The program design was itself partly based on our 2012 service value research, which was of itself highly innovative and progressive.

Importantly, our program provides confidence that the diverse basket of services that South Australian customers expect from SA Power Networks now and into the future have been thoroughly reviewed, analysed and integrated into our work programs. We have used advanced engagement techniques to explore and develop targeted programs of great interest to our customers.

Our innovative 'Directions and Priorities 2015 to 2020' consultation program, which described a proposed 'basket of services' and set out the indicative accompanying price path impacts for customers, was widely publicised and well-received among our stakeholders. Feedback through that process has been factored into this Proposal, as described in the preceding chapters, themselves built around the key services we provide to customers.

We believe that the service-price trade-off represented by this Proposal will be understood by our customers and stakeholders, as was our 'Directions and Priorities 2015 to 2020' consultation document.

In conclusion, this Proposal represents value for South Australians, reflective of the service-price trade-off discussed above:

- SA Power Networks has a long record of effective, balanced performance, and is a high-performing DNSP. We aim to be reliable, safe, prudent and efficient in all that we do, and we believe we are a leader in our industry on all key dimensions.
- our customers and our industry are changing. Our challenge is to continue delivering our services, and to adapt as circumstances demand, in order to continue to deliver value to our customers and stakeholders.
- we have considered these changes deeply, and we have gained a high level of customer and stakeholder insight and support through our engagement programs.
- on this basis, we have set appropriate balanced objectives and then developed a comprehensive Proposal that will deliver on the short and long term needs of our customers and stakeholders in an optimal way.
- we can deliver on these needs with a price path that will remain below CPI, consistent with the pricing expectation we clearly established in our customer engagement. Customers indicated that they valued our proposed programs of work, providing this price outcome could be met.

We consider this Proposal represents an appropriate balance of price and service that will meet the needs of South Australian customers and the wider community, and position us for sustained service delivery into the long term.

18 Classification of services and negotiating framework

18

18.1

NER and AER's Framework and Approach

Section 6.2 of the NER governs how the AER may classify distribution services for regulation as 'direct control services' (**DCS**) or as 'negotiated distribution services' (**NDS**). DCS are further divided into 'standard control services' (**SCS**) and 'alternative control services' (**ACS**). In classifying these services, the NER requires the AER to have regard to factors including the potential for competition for that service to develop and how classification might influence that development and the administration costs involved.

SCS typically include network planning, operation and maintenance services which benefit all customers. The costs to provide SCS are recovered through distribution use of system tariffs paid by all customers. ACS or NDS costs are generally more customer-specific services and recovered from the individual customers receiving these services.

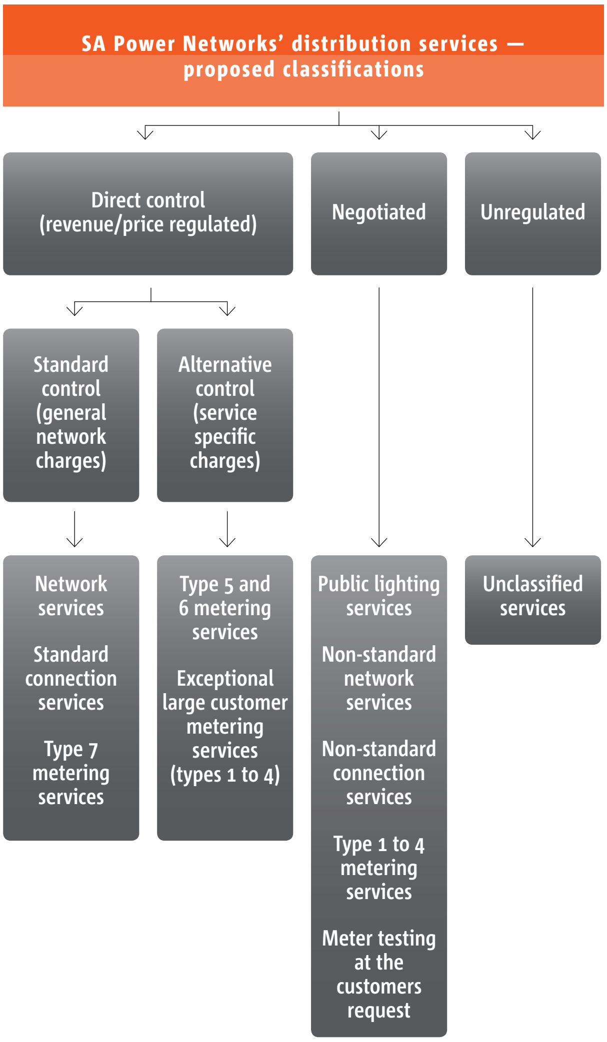
On 30 April 2014, the AER published its Framework and Approach Paper (**F&A**) (refer Attachment 7.6) and set out, amongst other things, its proposed classification of distribution services for the 2015–20 Regulatory Control Period (**RCP**).

The AER proposes to largely retain the existing classification of SA Power Networks' distribution services, with the following exceptions:

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

Figure 18.1 illustrates the AER's proposed classification.

Figure 18.1: AER's Proposed classification of SA Power Networks' distribution services



The proposed approach to classify most Type 5 and Type 6 metering services as ACS is because it is anticipated that these services may be subject to competition during the next RCP.

SA Power Networks proposes to adopt the AER's classification with the exception of including three additional services in the NDS 'other' category.

18.2

Standard Control Services

The AER set out its proposed classification of SCS in Appendix B of its F&A and these are summarised in Table 18.1.

Table 18.1: Standard Control Services 2015–20

Category	Service
Standard network services	All network services except: i. network services provided at the request of a distribution network user: (i) with higher quality or reliability standards, or lower quality or reliability standards (where permissible), than are required by the rules or any other applicable regulatory instruments, or (ii) in excess of levels of service or plant ratings required to be provided by SA Power Networks' assets, or ii. extension or augmentation of the distribution network associated with the provision of a new connection point or upgrading of the capability of a connection point to the extent that a distribution network user is required to make a financial contribution in accordance with the rules, or iii. other network services that are classified as negotiated distribution services.
Standard connection services	All connection services except: i. connection services provided at the request of a distribution network user: (i) with higher quality or reliability standards, or lower quality or reliability standards (where permissible), than are required by the rules or any other applicable regulatory instruments, or (ii) in excess of levels of service or plant ratings required to be provided by SA Power Networks assets, or ii. the provision of a new connection point or upgrading of the capability of a connection point to the extent that a distribution network user is required to make a financial contribution in accordance with the rules, or iii. other connection services that are classified as negotiated distribution services.
Unmetered metering services	The provision of metering services in respect of meters meeting the requirements of a metering installation type 7.

SA Power Networks does not propose any SCS classification that differs from the classification proposed in the F&A.

18.3

Alternative Control Services

In 2010 the AER reclassified the meter provision and meter reading services for certain metering services, changing the relevant costs from SCS to ACS. SA Power Networks developed tariffs for these metering services that were identifiable and cost reflective.

For the 2015–20 RCP, the AER in its F&A proposes to further modify the classification of metering services that will apply to SA Power Networks from 1 July 2015. Broadly, the AER has changed the classification so that all Type 5 and Type 6 metering related services, other than testing and investigation services requested and paid for by customers, will be ACS.

The AER set out its proposed classification of ACS in Appendix B of its F&A. Having regard to the information in Appendix B of the F&A, and the reasons given for the AER's proposed approach in the F&A document, SA Power Networks has summarised the AER's proposed classification of ACS metering services in Table 18.2.

Table 18.2: Alternative Control Services 2015–20

Standard small customer metering services	Exceptional large customer metering services
• meter provision services;* • meter installation services; and • regular meter reading services; in respect of meters meeting the requirements of metering installation Types 5 and 6;** and • energy data and storage services (excluding those required for standard control services); and • unscheduled meter reading and metering investigation,*** directly associated with Types 5 and 6 metering services.	• meter provision services* provided in respect of meters meeting the requirements of a metering installation Type 1, metering installation Type 2, metering installation Type 3 or metering installation Type 4 installed prior to 1 July 2000. • meter provision services* provided in accordance with the requirement of clause 27 of SA Power Networks distribution licence as in force at 30 June 2005.

Notes:
* Meter provision services include, but are not necessarily limited to, any asset related and administrative costs associated with the provision, installation, maintenance, and replacement of the meter (including circumstances in which the meter is replaced by that of another meter provider).
** Including Type 5 and Type 6 import/export meters.[50]
*** Relating only to the costs associated with non-chargeable unscheduled meter reading and metering investigation.[51]

SA Power Networks does not propose a classification for ACS that differs from the classification in the F&A. For the avoidance of doubt, SA Power Networks proposes to charge meter exit and transfer fees in situations where a customer with an existing SA Power Networks meter selects another metering provider unless an alternative approach is agreed with the AER which keep the business whole for our previous mandated investment in meters. These are discussed further in Section 29.3.

18.4

Negotiated distribution services

SA Power Networks will continue to provide a broad range of NDS to customers during the 2015–20 RCP. The services are summarised in Table 18.3.

Table 18.3: Negotiated Distribution Services 2015–20

Negotiated Distribution Services 2015–20
Non-standard network services
Non-standard connection services
New and upgraded connection point services
Non-standard small customer metering services
Large customer metering services
Public lighting services
Stand-by and temporary supply services
Asset relocation, temporary disconnection and temporary line insulation services
Embedded generation services
Other services

These NDS are outlined in further detail in Appendix B of the AER's F&A document (refer Attachment 7.6).

50 Framework and Approach, p33
51 Framework and Approach, Table 4, p28, Table 5, p30, p31, p51

SA Power Networks considers that the AER's proposed classification of NDS as set out in the F&A document is appropriate. However, SA Power Networks considers that three minor changes to the AER's proposed classification of NDS are necessary.

SA Power Networks proposes that the following three additional services be included in the classification of 'Other' NDS. The proposed new services are:

- attendance at the customer's premises at the customer's or their agent's request, 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.

By doing so, SA Power Networks seeks to make it clear to customers that it is entitled to recover the costs related to attending faults that were not caused by its infrastructure or equipment, third party requested alterations or upgrades to network infrastructure required to cater for their requirements, and the costs related to obtaining, verifying and providing energy data relevant to Local Government Councils.

SA Power Networks believes that it is appropriate to classify such services as NDS. These services relate to the distribution network and are provided at the request of, and for the benefit of, specific and identifiable customers.

18.5

Negotiating framework

Section 6.7 of the NER governs principles and requirements for accessing NDS. The AER must determine Negotiated Distribution Service Criteria (**NDSC**) in accordance with these principles and SA Power Networks must apply these criteria when negotiating access terms including prices and access charges. SA Power Networks must also prepare a negotiating framework document setting out the procedure to be followed during negotiations between SA Power Networks and any person wishing to receive NDS. NER 6.12.1 provides for the AER to make a decision on the negotiating framework and the NDSC to apply for 2015–20.

The negotiating framework that SA Power Networks proposes to apply for the 2015–20 RCP is provided for approval at Attachment 18.1. This document is proposed to replace SA Power Networks' Negotiating Framework 2010–15. It has been prepared in accordance with SA Power Networks' obligations under clause 6.7.5(a) of the Rules.

The proposed Negotiating Framework 2015–20 is virtually identical in substance and structure to SA Power Networks' Negotiating Framework 2010–15, but has been modified to reflect changes in relevant regulatory arrangements and to improve the functionality of the document and its administration.

The structure of the Negotiating Framework 2015–20 has not changed. It is structured as follows:

- **Part A** sets out arrangements for the classification of negotiated distribution services and the commercial obligations applicable to SA Power Networks and Service Applicants
- **Part B** contains the provisions for Individually Negotiated Services
- **Part C** contains the provisions for Indicative Price List Services
- **Part D** contains administrative provisions that apply to both classifications of negotiated distribution services
- **Schedule 1** lists the classification of negotiated distribution services
- **Schedule 2** sets out the NDSC
- **Schedule 3** sets out SA Power Networks' information disclosure obligations for Indicative Price List services.

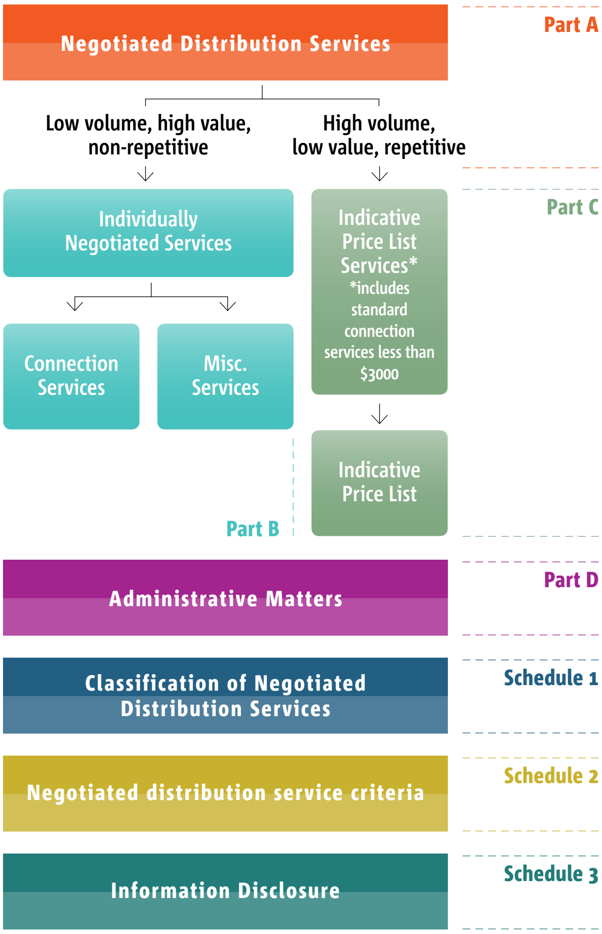
The structure of the Negotiating Framework 2015–20 is shown graphically in Figure 18.2.

The main changes to the Negotiating Framework document are:

- to remove elements of the Negotiating Framework 2010–15 that are now accommodated in SA Power Networks' Connection Policy (Part B) discussed in Section 12.2.3 of this Proposal and appears at Attachment 12.1;
- to include additional text to enhance the clarity of certain terms that have been the subject of conflicting interpretation (cl 6, and definitions);
- to make clear that the negotiation of an indicative price list service is essentially the negotiation of an individually negotiated service (Part B and Part C);
- to rationalise SA Power Networks' obligations to publish commercial information and information relating to negotiations (cl 20, cl 26, and Schedule 3);
- to update Schedule 1 for the recent changes to the AER's F&A; and
- editorial changes.

SA Power Networks has not proposed any change to the NDSC.

Figure 18.2: Structure of SA Power Networks' Negotiating Framework



19 Control mechanisms

19

19.1

Standard control services — revenue cap

In its Framework and Approach Paper (**F&A**)(refer Attachment 7.6), the AER decided that it will apply a revenue cap form of control to SA Power Networks' SCS in the 2015–20 RCP. This decision is binding on the AER and SA Power Networks.

The F&A sets out the revenue cap formulae[52] to apply during the 2015–20 RCP.

Essentially, the AER will set the total revenue allowed for each regulatory year of the RCP. SA Power Networks must then recover revenue equal to or less than the total revenue for that year. We will comply with the 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. At the end of each regulatory year, we will report actual revenues to the AER. The AER will account for differences between the actual revenue recovered and the total revenue in future years. This operation occurs through an 'overs and unders' account, whereby any over-recovery (under-recovery) is deducted from (added to) the total revenue in future years. Annual revenue allowances will be adjusted for outcomes of the various incentive schemes and may incorporate pass-through events.

It is important to note that transmission costs and costs associated with the South Australian photo-voltaic feed-in-tariff scheme, which are also passed through to SA Power Networks, operate outside the SCS revenue cap arrangements. These costs are passed through to SA Power Networks and are included in our network prices as separate tariff elements to the revenue cap elements.

19.2

Alternative control services — price caps

In the 2010–15 RCP, SA Power Networks' ACS tariffs are subject to a weighted average price cap (**WAPC**) form of price control, which provides the flexibility to rebalance prices during the RCP to meet changing circumstances.

For the 2015–20 RCP, the AER has decided to apply a price cap form of control to each of the individual ACS and has set out the proposed formula to give effect to this control mechanism in the F&A. In accordance with NER 6.8.1 (f) and 6.12.3 (c), the AER's decision on the form of control is binding on the AER and SA Power Networks.[53] 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 the new ACS classification, the costs that will need to be recovered through ACS tariffs include a much greater component of fixed costs, particularly service contracts and information technology assets, as well as meter asset costs and overheads. Customer number forecasting risk can be substantially mitigated by meter exit fees, but only where the fees reflect the actual costs associated with the transaction, including an appropriate share of the fixed costs that are unavoidable for the term of the RCP. This being the case, SA Power Networks' ACS Proposal includes the use of meter exit and transfer fees. We have proposed two new transfer fees in respect of smart-ready meters and a new exit fee in respect of SA Power Networks' existing Type 6 standard meters. In proposing the use of exit and transfer fees and in developing specific tariffs, we have noted the AEMC's recommendations regarding exit fees in its Power of Choice review.[54]

We have considered other options for ACS that could obviate the requirement for meter transfer fees in respect of existing standard meters. Such alternatives include the potential to transfer fixed costs from ACS to SCS, as conceived by the AER in the F&A paper; to establish an explicit pass-through mechanism in the next RCP; or to establish a true-up mechanism to apply in the 2020–25 RCP. Each of the potential options has merit, but SA Power Networks believes that its proposed approach is congruent with the current Standing Council on Energy and Resources' (**SCER's**) "Expanding competition in metering and related services" Rule change proposal, is efficient and transparent, and best meets the long term economic objectives reflected in the National Electricity Objective. On finalisation of the Rule change, expected in April 2015, SA Power Networks will review its approach and incorporate any required changes in our Revised Proposal which will be submitted in July 2015. The F&A sets out the proposed formula to apply to ACS during the 2015–20 RCP.

Essentially, 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.

The 'A' factor is an adjustment factor available to reflect the cost impact of circumstances that are outside the control of the DNSP, or that were so uncertain as to be impossible to be efficiently factored in to the Regulatory Proposal. SA Power Networks' ACS Proposal envisages the use of the A factor for such purposes as the recovery of residual charges when customers choose to replace assets before the end of their economic life, the impacts of the annual updating of cost of debt or of the otherwise unrecoverable costs associated with extraordinary customer churn.

The A factor must remain a dynamic element of the price control mechanism. It is essentially an in-period true-up mechanism and as such is unable to be calculated or estimated at this time. The A factor would form a component of SA Power Networks' Pricing Proposal in respect of ACS for each regulatory year of the next RCP.

52 F&A: p49
53 F&A: p. 13, p. 39.
54 Final Report, Power of choice review — giving consumers options in the way they use electricity, AEMC, 30 November 2012.

20
Forecast capital expenditure

20

In this chapter of the Proposal, we explain our capital expenditure forecast for the 2015–20 RCP. SA Power Networks considers this expenditure is required to meet the capital expenditure objectives described within the National Electricity Rules (**NER** or **Rules**). This chapter should be read in conjunction with Chapter 9 through to Chapter 16 and the referenced attachments to gain a full appreciation of our Proposal.

This chapter outlines regulatory obligations, discusses 2010–15 RCP outcomes, describes approaches to forecasting expenditures for the 2015–20 RCP, details the 2015–20 RCP forecast expenditures and provides context and reasoning that support the expenditure forecasts, as appropriate. However, the chapter scope and content is extensive, so Table 20.1 provides a chapter structure aid to assist the reader.

SA Power Networks has also provided additional information to the AER in support of this forecast in compliance with the requirements of clauses 6.5.7(b), 6.8.2(c)(2) and 6.8.2(d) of the NER and the Regulatory Information Notice (**RIN**) dated 25 August 2014 (refer to Reset RIN cross reference table Attachment 1.2).

For sections 20.1 to 20.7 document references will be included in Attachment 20.1, Network Document Reference Map. This map outlines the relationships to the Network supporting documentation.

Table 20.1: Forecast capital expenditure — chapter structure

Sections	Purpose	Content
20.1 to 20.4	Overview of consolidated capital expenditure outcomes and forecasts	• NER requirements • 2010–15 RCP consolidated capital expenditure outcomes • High level capital expenditure forecasting approach • 2015–20 RCP consolidated capital expenditure forecast
20.5 **20.6** **20.7**	Replacement category expenditure outcomes and forecasts Augmentation category expenditure outcomes and forecasts Connections category expenditure outcomes and forecasts	• 2010–15 RCP category capital expenditure outcomes • Category expenditure forecasting approach • 2015–20 RCP category expenditure forecast • Reasoning underpinning category expenditure forecast
20.8	Non-network sub-category expenditure outcomes and forecasts	• Sub-categories of IT, Network communications, Property, Vehicles, Other • 2010–15 RCP sub-category capital expenditure outcomes • Sub-category expenditure forecasting approach • 2015–20 RCP sub-category expenditure forecast • Reasoning underpinning sub-category expenditure forecast
20.9	Alternative Control Services (**ACS**) expenditure outcomes and forecasts	• 2010–15 RCP category capital expenditure outcomes • Category expenditure forecasting approach • 2015–20 RCP category expenditure forecast • Reasoning underpinning category expenditure forecast
20.10	Program deliverability	• Strategies to ensure deliverability of our Proposal

20.1

Rule requirements and associated regulatory obligations

Rules 6.8.2(c)(2) and 6.5.7(a) 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 necessary to achieve the capital expenditure objectives.

The capital expenditure objectives are to:

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

    to the relevant extent:

    c. maintain the quality, reliability and security of supply of *standard control services*;
    d. maintain the reliability and security of the *distribution system* through the supply of *standard control services*; and
4. maintain the safety of the *distribution system* through the supply of *standard control services*.

The AER must accept SA Power Networks' proposed capital expenditure forecast included in the building block proposal if the AER is satisfied 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, prior period performance and importantly the extent to which the capital expenditure forecast addresses 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.

In this chapter, we will demonstrate our compliance with the capital expenditure criteria by demonstrating that:

1. the identified scope is consistent with SA Power Networks' regulatory obligations, good electricity industry practice and the requirement to achieve the capital expenditure objectives;
2. the demand and cost inputs for network expenditures have been forecast using a unit cost methodology which has been independently reviewed;
3. the scoping processes are reasonable and utilise these demand inputs and costs;
4. the costing processes are reasonable and incorporate realistic cost inputs, resulting in an efficient capital expenditure forecast;
5. the identified scope can be delivered by SA Power Networks; and
6. benchmarking data analysis shows SA Power Networks is an efficient network operator.

Further, where expenditure differs significantly from that of the current RCP, such differences are explained.

It should be noted that the costs incorporated within our forecast capital expenditure for the 2015–20 RCP are consistent with the incentives provided within the Service Target Performance Incentive Scheme (**STPIS**) applicable to SA Power Networks for the 2015–20 RCP. In particular, our forecast of the capital expenditure required for the delivery of Standard Control Services (**SCS**) during the 2015–20 RCP is predicated on SA Power Networks maintaining, not improving, the underlying reliability of its electricity distribution network.

However, our customers have also told us they wish us to mitigate the impacts of severe weather events, which are generally excluded from the current STPIS. Some of the costs incorporated within our forecast capital expenditure for the 2015–20 RCP have been included to address these concerns of electricity consumers, as discussed in Chapter 10.

Further discussion of the relevant capital expenditure objectives and the associated regulatory obligations for each capital expenditure category is provided in the respective section of this chapter.

20.2

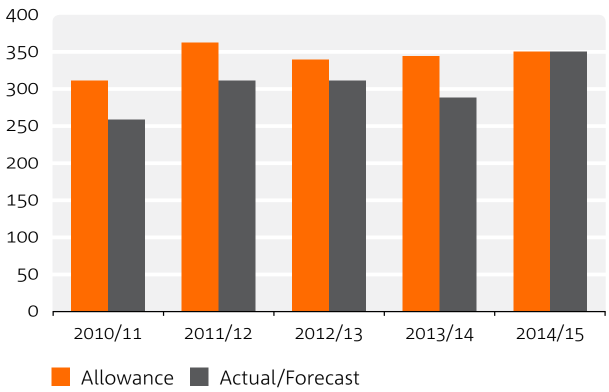
Current period performance

In the current RCP, we have undertaken a significant investment program consistent with the AER approved allowances. The original capital program was largely focused on augmenting our network ensuring our ability to meet expected demand for SCS. We required a significant step increase in augmentation, primarily driven by Electricity Transmission Code (**ETC**) changes and forecast spatial demand growth. There was also a requirement to manage the condition of our ageing and deteriorating infrastructure, refurbishing or replacing defective assets to maintain the safety, quality, reliability and security of supply in delivering SCS.

For our 2010–15 RCP, the AER determined an efficient allowance of $1,590 million ($ 2009–10). The allowance was based on total gross capital expenditure less capital contributions. Our forecast total net capital expenditure for the current RCP is $1,526.6 million (nominal) as outlined in Table 20.2 and Figure 20.1.

A comparison with the capital expenditure for the 2005–10 RCP is provided in Attachment 20.73.

Figure 20.1: Comparison of the AER allowance and SA Power Networks net capital expenditure for the 2010–15 RCP ($ million, nominal)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

SA Power Networks has invested prudently and efficiently in network and non-network assets in the current regulatory period spending $1,526.6 million, being $184.3 million less than the AER approved allowance for the current RCP. This underspend (of $184.3m) can be explained by the prudent reduced capital expenditure arising from lower capacity upgrades and customer connections requirements. The incentive based regulatory regime encourages DNSPs to focus on the efficiency in the delivery of capital investments undertaken throughout a regulatory period. Furthermore there is a recognition that circumstances are likely to change during a regulatory period and where it is prudent to defer capital expenditure whilst still meeting service standards then DNSPs are encouraged to do so. This results in a lower regulatory asset base and lower costs to consumers in the next regulatory period.

Variations in SA Power Networks' capital expenditure in the 2010–15 RCP have resulted from a number of factors including but not limited to:

- Lower capacity investments have been required to meet peak demand. This has occurred as a result of the slower than anticipated recovery from the Global Financial Crisis by the South Australian economy, the longer time period for the expected flow-on from the mining developments (eg Olympic Dam delays) and a higher than forecast take up of solar PV among residential customers (185,000 approvals compared to forecast 35,000);
- Lower customer connection work driven by lower customer growth and subdued housing market trends;
- Increased expenditure on asset replacements to progressively address the significant level of defects identified through our increased asset inspection program and the associated step change in the assessed defective condition of network assets;
- Adopting cost-efficient alternatives to full asset replacement where such actions are feasible, such as pole plating; and
- Achieving cost efficiencies through improved business processes, one-off design improvements and a continued focus on equipment and service costs.

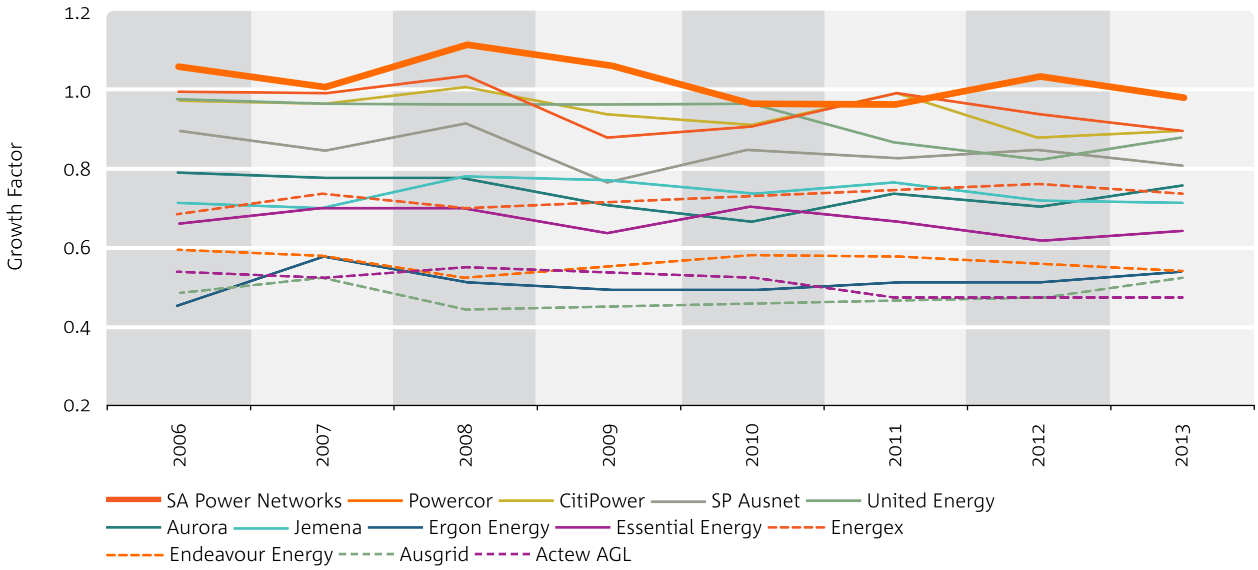
In respect of this last point, SA Power Networks has engaged expert consultants Huegin Consulting (**Huegin**) to conduct modelling to measure SA Power Networks' efficiency relative to other DNSPs in the National Electricity Market (**NEM**), based on the AER's preferred specification of a Multilateral Total Factor Productivity (**MTFP**) model (discussed in Section 4.2). Huegin's results indicate that SA Power Networks has consistently been the most efficient DNSP in the NEM (see Figure 20.2). Further detail regarding Huegin's analysis is contained in Attachment 4.1.

SA Power Networks has for many years pushed the utilisation of its network infrastructure very hard so as to extract the maximum benefit and service life from its network infrastructure (and notwithstanding the limitations of South Australian customers' peaky load profile) prior to investing in replacement or refurbished assets. Figure 20.3 clearly identifies that over the last 10 years SA Power Networks' rate of investment in the network has been the lowest of all distributors.

Table 20.2: Total net capital expenditure allowance and actual/forecast capital expenditure for the 2010–15 RCP ($ million, nominal)

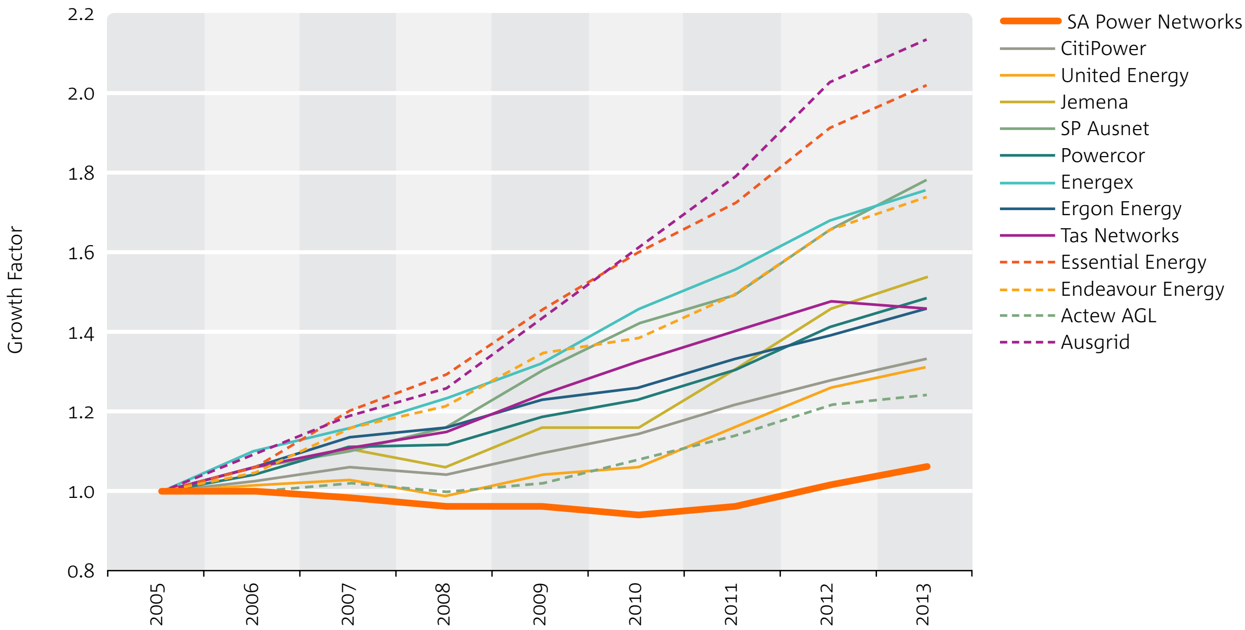
	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Approved allowance	310.4	363.9	339.6	347.1	349.8	**1,710.9**
Actual/forecast expenditure	256.1	312.7	321.4	286.7	349.6	**1,526.6**

Figure 20.2: Multilateral total factor productivity for each NEM DNSP, based on the AER's preferred MTFP model specification[55]



SOURCE: HUEGIN (ATTACHMENT 4.1,), BASED ON ECONOMIC BENCHMARKING RIN DATA RELEASED BY THE AER, 2014

Figure 20.3: Real regulated asset base (**RAB**) growth — NEM DNSPs



SOURCE: SA POWER NETWORKS ANALYSIS, BASED ON AUSTRALIAN ENERGY REGULATOR BENCHMARKING DATA 2014

55 AER, 'Expenditure Forecast Assessment Guideline: Explanatory Statement', Nov 2013, p. 151.

20.3

Network capital expenditure development process

This section outlines the process and inputs used in developing the capital expenditure plans and forecasts for network infrastructure for the 2015–20 RCP.

Figure 20.4 illustrates the process utilised for the development of network capital expenditure plans. Non-network categories (IT, Property, Fleet and other) have their own individual processes and are described in detail in Section 20.8.

The scope of each capital expenditure plan has been developed using a risk based approach that aligns with SA Power Networks' capital governance procedures (refer Attachment 20.51). This approach ensures that we can:

- meet forecast demand over the 2015–20 RCP;
- comply with all applicable *regulatory obligations or requirements* associated with the provision of *standard control services*;
- deliver levels of customer service to meet our jurisdictional service standard obligations;
- achieve acceptable levels of business risk; and
- achieve acceptable levels of safety risk to the public and employees.

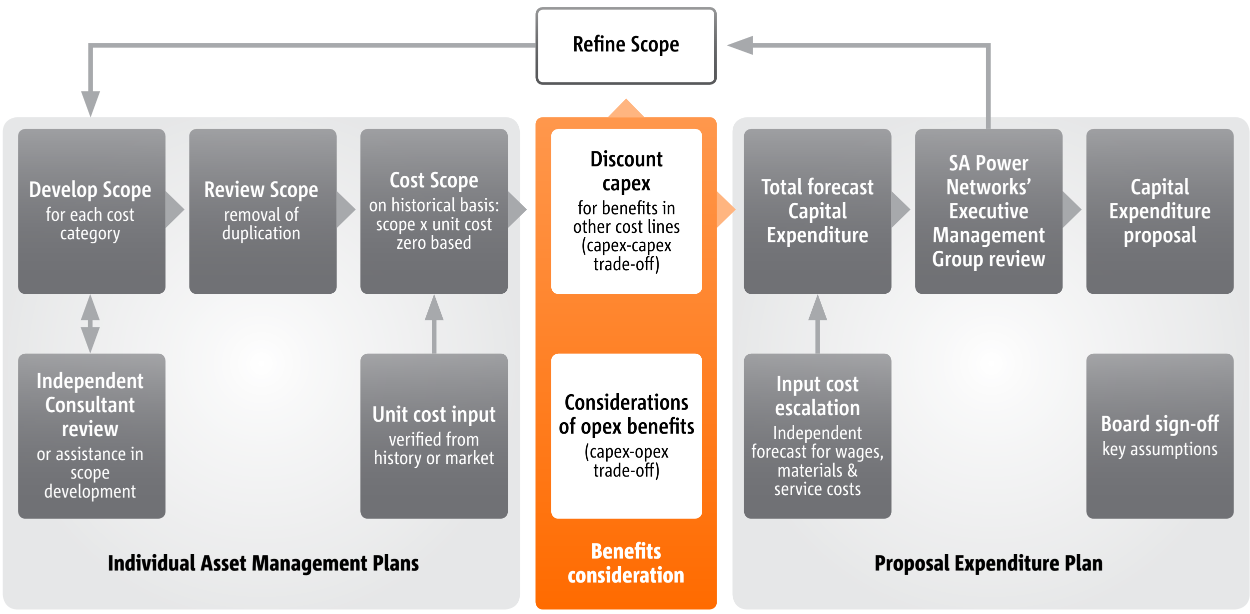
Key inputs into the development of the specific asset management plans and forecasts for replacement and augmentation capital expenditures include:

- Regulatory obligations — discussed in Sections 7.2, 20.1 and 20.5.1;
- Jurisdictional service standards — essentially requiring that SA Power Networks maintain reliability and customer service at historic levels of performance — discussed in Section 7.2 and Chapter 9;
- Customer preference and expectations from our Customer Engagement Program — outlined in Chapter 6 and Chapters 9–16;
- Condition assessments and maintenance risk values (**MRV**) — discussed in Section 20.5.2;
- Network planning criteria — discussed in Section 20.6;
- Spatial peak demand forecasts — discussed in Section 20.6; and
- Customer connection forecasts — discussed in Section 20.7.

The capital expenditure forecasts are costed on a 'bottom up basis' utilising unit costs based on historical 'building block' estimates for similar projects.

In developing our capital expenditure forecasts, we have also considered the substitution possibilities between operating and capital expenditure. The interaction between individual capital expenditure categories has been considered by performing a 'trade-off' or benefits review. This review has been conducted prior to aggregation of the capital expenditure categories, whereby each proposed expenditure scope is examined for potential benefits in other expenditure lines and, where trade-off possibilities are considered prudent and efficient, corresponding adjustments are made.

Figure 20.4: Network capital expenditure planning and forecast process



SOURCE: SA POWER NETWORKS EXPENDITURE FORECASTING METHODOLOGY, ATTACHMENT 7.5

The forecast capital expenditures are also escalated for forecast changes in the real input costs anticipated over the 2015–20 RCP. These escalators are consistent for both capital and operating expenditures as detailed in Section 21.9. The methodologies used are outlined below:

- **Labour:** SA Power Networks has applied a positive real escalation rate to relevant labour costs in the 2015–20 RCP, based on the Enterprise Bargaining Agreements of a comparator group of DNSPs as developed by Frontier Economics.
- **Contracted construction and labour services:** SA Power Networks has applied a real cost escalation rate to Contracted Construction and Labour Services costs based on forecasts provided by BIS Shrapnel, of the Construction sector Wage Price Index for South Australia.
- **Materials:** SA Power Networks has applied a weighted real materials escalation rate to relevant materials costs. The methodology employed combines forecasts of input component weights (copper, aluminium, steel and crude oil) developed by Competition Economists' Group (**CEG**) and the conversion of these forecasts into a weighted materials escalation rate utilising Jacobs' most recent analysis (refer Attachment 20.4, Nominal Material Cost Escalation Indices Forecast, Jacobs, September 2014) of distribution and transmission price and contract information.
- **Land:** SA Power Networks has applied a real land cost escalation rate to the relevant costs of future sites to be acquired in the 2015–20 RCP. Maloney Field Services has provided current independent valuations of sites identified by SA Power Networks and an appropriate land cost escalation rate has been applied to these valuations, in order to forecast the purchase price of these properties, (refer Attachment 20.5).

A summary of the cost escalation rates applied to capital expenditures is outlined in Table 20.3. For further detail regarding the approach used to develop these escalation rates (refer to Section 21.9).

The expenditure build-up is undertaken in compliance with SA Power Networks' Cost Allocation Method (**CAM**), as approved by the AER (refer Attachment 20.7).

The SA Power Networks Executive Management Group (**EMG**) and Board have reviewed and endorsed the capital expenditure plans at strategic stages in the capital expenditure development process. As required under the NER, the SA Power Networks Directors have certified the reasonableness of the key assumptions underlying the expenditure forecasts (refer Attachment 1.1).

20.4

Summary of proposed capital expenditure for 2015–20 RCP

The AER has categorised capital expenditure for SCS into four high level categories by primary driver. These categories are as follows:

- replacement — capital expenditure incurred to address deterioration of assets, refer Section 20.5 of this chapter;
- augmentation — capital expenditure typically triggered by a need to build or upgrade network assets (refer Section 20.6 of this chapter);
- connection and customer driven works — capital expenditure necessary to connect customers to the network and other customer related works (refer Section 20.7 of this Chapter); and
- non-network — capital expenditure for activities not directly associated with the distribution network (refer Section 20.8 of this chapter).

Figure 20.5 shows SA Power Networks' forecast of the total gross capital expenditure for SCS that we consider will be required during the 2015–20 RCP in order for us to achieve the capital expenditure objectives described in Section 20.1 of this chapter.

As evident in Figure 20.5, a step increase in expenditure from the current RCP will be required in the 2015–20 RCP. Table 20.4 tabulates SA Power Networks' total forecast net capital expenditure for SCS for the 2015–20 RCP.

ACS expenditure relates to metering services provided by SA Power Networks, refer to Section 20.9 of this chapter. Table 20.5 shows SA Power Networks' forecast of the total net capital expenditure for ACS that we consider will be required during the 2015–20 RCP in order for us to achieve the objectives described in Section 20.1 of this chapter as they are applied to the provision of ACS.

Under a proposed NER change arising from the *Power of Choice* review, metering services are to become fully contestable. These proposed reforms are subject to consultation that will run until 2015, with final NER changes expected to come into effect in 2016.

The following sections describe in detail the forecast capital expenditure programs for SCS and ACS.

Table 20.3: Real escalation rates applied to capital expenditure, real %

Escalation rates (real %)	2015/16	2016/17	2017/18	2018/19	2019/20
Labour	1.66	1.66	1.77	1.77	1.77
Contracted construction and labour services	0.50	0.90	1.10	1.40	1.80
Materials	0.71	0.12	0.01	-0.02	0.02
Land	5.96	5.96	5.96	5.96	5.96

Figure 20.5: Forecast gross capital expenditure trends and components (June 2015, $ million)

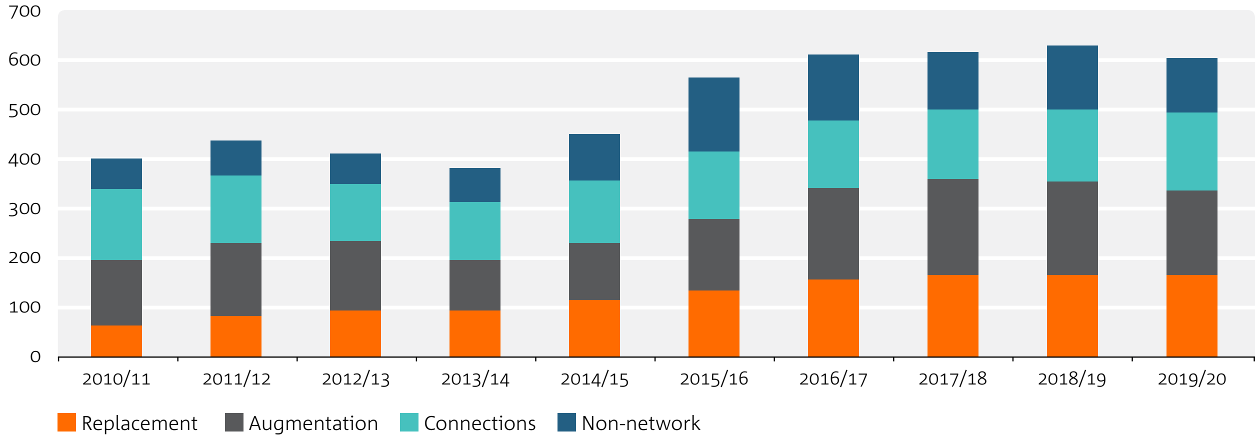


Table 20.4: SCS forecast net capital expenditure for the 2015–20 RCP (June 2015, $ million)

	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	149.4	131.5	111.4	123.3	104.5	**620.1**
Total SCS expenditure forecast (net)	**463.6**	**508.3**	**510.4**	**517.8**	**485.4**	**2,485.5**

Table 20.5: ACS forecast net capital expenditure for the 2015–20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
New connections expenditure	2.7	2.7	2.8	2.8	2.8	**13.8**
Replacements expenditure	7.1	6.8	6.9	7.6	4.2	**32.6**
IT Infrastructure expenditure	0.2	0.2	1.7	0.2	0.2	**2.6**
Customer initiated work	5.7	7.4	12.0	11.9	12.5	**49.4**
Total gross capital expenditure	**15.7**	**17.1**	**23.3**	**22.5**	**19.7**	**98.4**
Customer contributions	(5.7)	(7.4)	(12.0)	(11.9)	(12.5)	**(49.4)**
Total net capital expenditure	**10.0**	**9.8**	**11.3**	**10.6**	**7.3**	**49.0**

20.5

Replacement expenditure

This section explains why our forecast capital expenditure for replacement is required in order to achieve the capital expenditure objectives and how that forecast expenditure reasonably reflects the capital expenditure criteria and takes into account relevant capital expenditure factors. This section should be read in conjunction with Chapters 9 'Keeping the power on for South Australians' and 11 'Responding to severe weather events', and the referenced attachments to gain a full appreciation of our Proposal.

20.5.1 Relevant capital expenditure objectives and associated regulatory obligations

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

6.5.7(a)(2) comply with all applicable *regulatory obligations or requirements* associated with the provision of *standard control services*; and

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

Our regulatory obligations relating to the provision of standard control services 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;
- the requirements of our Distribution Licence;
- the 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 (in particular, Section 12 of Schedules 1-4);
- the ESCoSA set service standards for reliability; and
- Chapter 5 of the NER (in particular, clauses 5.2.1 and 5.2.3 which require us to maintain and operate the network 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 our in Schedule 5.1).

ESCoSA Service Standards Framework

The ESCoSA Service Standard Framework (**SSF**) prescribes the reliability and customer service levels that we must deliver to customers. The service levels that will apply for the 2015–20 RCP are based on the frequency and duration of unplanned interruptions in four broad feeder categories (CBD, Urban, Rural Short and Rural Long). On the 8th October 2014 ESCoSA finalised the service standards and targets which reflect the average historical performance levels during 2009/10 to 2013/14. These will exclude network performance during severe or abnormal weather events using the Institute of Electrical and Electronics Engineers (**IEEE**) Major Event Day (**MED**) exclusion methodology. The specific targets under the service standards were discussed in Chapter 9 and are shown again for convenience in Table 20.6. These targets were approved by ESCoSA on 8 October 2014 and the EDC has been amended to reflect the new targets from 1 July 2015.

Table 20.6: Network reliability service standards 2015–20

	CBD	Urban	Short Rural	Long Rural	Equivalent Overall
USAIDI (minutes)	15	120	220	300	165
USAIFI	0.15	1.30	1.85	1.95	1.50

Note: The targets exclude reliability performance on MEDs.

ESCoSA-approved 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.

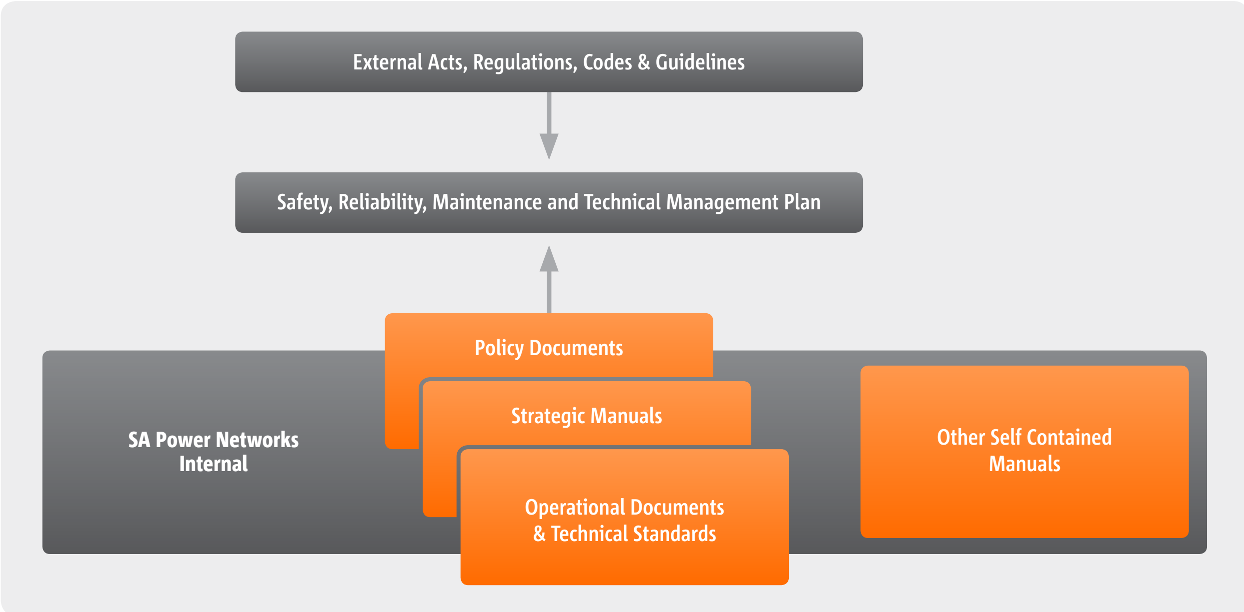
The SRMTMP incorporates by reference a hierarchy of internal SA Power Networks documents (refer to Figure 20.6). These internal documents are considered and updated during the annual SRMTMP review and approval process as they form an integral part of our SRMTMP. The SA Power Networks internal documents include the Network Maintenance Manual (No. 12) and the Line Inspection Manual (No. 11) which outline the:

i. 'system of maintenance';
ii. 'predetermined processes'; and
iii. 'managed replacement programs'

instituted by SA Power Networks for the purposes of meeting (amongst other things) its obligations under Section 12 of Schedules 1–4 of the Electricity (General) Regulations.

The internal SA Power Networks documents which form part of the SRMTMP include applicable standards and requirements for the rectification of certain types of network asset defects within a specified period after the identification of that defect. The Network Maintenance Manual (No. 12), in particular, specifies the inspection cycles for all asset categories and the assignment of maintenance priorities for those asset categories (ie the specified timeframes to rectify identified asset defects). In other words the SRMTMP defines what amounts to a network asset defect and mandates the timing for the rectification of that defect.

Figure 20.6: SRMTMP referenced internal document structure



SOURCE: SA POWER NETWORKS 2014

The SRMTMP and the internal documents which are incorporated by reference into the SRMTMP are required by the Electricity Act and our Distribution Licence to be approved by ESCoSA on the recommendation of the Office of the Technical Regulator (**OTR**). As noted above, SA Power Networks is required to comply with the ESCoSA-approved SRMTMP under its Distribution Licence and the Electricity Act. The relevant standard setting bodies for safety, reliability, maintenance and technical compliance are therefore ESCoSA and the OTR.

It follows that the ESCoSA-approved SRMTMP, together with clause 8 of our Distribution Licence and sections 25(1) and 60(1) of the Electricity Act impose a regulatory obligation on SA Power Networks to manage the integrity, safety and reliability of the network in accordance with the requirements of the SRMTMP (and the SA Power Networks internal documents which are incorporated by reference into the ESCoSA-approved SRMTMP). Attachment 20.10 provides a copy of the most recent ESCoSA approval of our SRMTMP.

The SRMTMP sets the level of safety risk that must be maintained under capital expenditure objective 6.5.7(a)(4). However, whilst the SRMTMP is approved annually and is subject to annual audits of compliance, the criteria for the identification of defects and the stipulated time for remedying such defects have remained constant over many years. What has occurred during the current RCP is an increase in the frequency and scope of our asset inspections which has resulted in the identification of an increased number of defects consistent with those criteria. This has led to a corresponding increase in the associated network risks which now exceed the long standing acceptable risk levels which have applied under the SRMTMP for many years.

An audit of SA Power Networks' compliance with the SRMTMP was recently undertaken by engineering consultant GHD. It included a review of the SRMTMP (that was published and approved, on the recommendation of the OTR, by ESCoSA in August 2013) and each of the manuals listed in the hierarchy of internal documents referred to in Section 2.1 of the SRMTMP.

In the section of the GHD Audit Report relating to Network Maintenance Manual (No. 12), it was stated that:

'SA Power Networks is in process of reviewing defect close out strategies with the aim to meet and discuss with the OTR and seek strategy acceptance before reset submission.' (refer Attachment 20.9)

With the significant volume of defects identified, increased defect rectification work is required to return the risk level to acceptable and prudent levels. The OTR acknowledged the need for this defect rectification work in its letter of 17 June 2014 advising that:

'We also note from page 61 that defect close out strategies are currently under review.'

SA Power Networks met with the OTR on the 25th of August and informed them of:

- the change to the assessed network risk level arising from the increase in the frequency and the scope of asset inspections; and
- the significantly increased volume of defect rectification work required to return the risk level to the acceptable historical levels, consistent with the SRMTMP, over the next 10 years.

The OTR acknowledged the information presented to them and that SA Power Networks was undertaking a prudent long term approach to managing this issue.

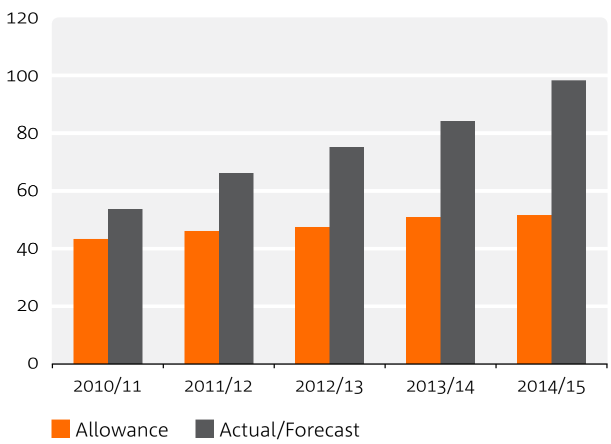
20.5.2 Current period outcomes for asset replacement

Replacement expenditure is non-demand driven capital expenditure to replace defective assets with their modern equivalent at the end of the asset life or to replace an asset at risk of failure which could result in compromised safety or a failure to meet our service standard targets. This category of capital expenditure also encompasses refurbishment expenditure which cost effectively extends the economic life of assets.

This expenditure can be associated with the replacement of assets either from failure (unplanned asset replacement) or on the basis of age and condition, having regard to the levels of risk being managed (planned replacements).

In the current RCP the total replacement expenditure is forecast to be $382 million, $143 million above the AER allowance of $239 million (June 2015 $), (excluding safety related replacement expenditure). Figure 20.7 details our actual/forecast replacement expenditure compared to allowance for the current RCP.

Figure 20.7: Replacement capital expenditure 2010–15 (June 2015, $ million)



At the time of lodging our regulatory reset proposal for the 2010–15 RCP, we forecast a requirement for replacement expenditure of $467 million ($2010) (excluding safety related replacements), based on our view of the replacement expenditure required as we moved from a methodology where we replaced assets on failure, to an approach where we replace assets on the basis of age and assessed condition, having regard to the historical levels of risk acceptable to SA Power Networks and embedded in the SRMTMP. This proposal recognised that as the majority of SA Power Networks' assets were installed in the 1950s, 1960s and 1970s and were therefore more likely to exhibit higher levels of defects as compared to newer assets, and with a historically low expenditure on asset replacement (pre 2010), there was expected to be an increased level of replacement expenditure required during the 2010–15 RCP.

As shown in Figure 20.8, SA Power Networks has the oldest electricity assets in Australia.

It was SA Power Networks' view, based on our knowledge of the asset defects that existed at that time, that an increase in asset replacement expenditure in 2010–15 was required to maintain an acceptable level of risk and achieve the capital expenditure objectives as set out in clauses 6.5.7(a)(2) and (4) and our SRMTMP (refer Attachment 7.2) as approved by ESCoSA.

In making its decision for the 2010–15 RCP, the AER agreed with our proposed condition-based replacement methodology but rejected the manner in which our approach was applied, primarily because our replacement forecast risk assessment had not been applied consistently across individual asset management plans and in some cases, in the AER's view, unsupported adjustments were made to the risk criteria to align the risk of failure to asset age. Essentially, we were unable to sufficiently demonstrate the increased expenditure was prudent and efficient due to our approach being primarily aged-based owing to the lack of actual asset condition information.

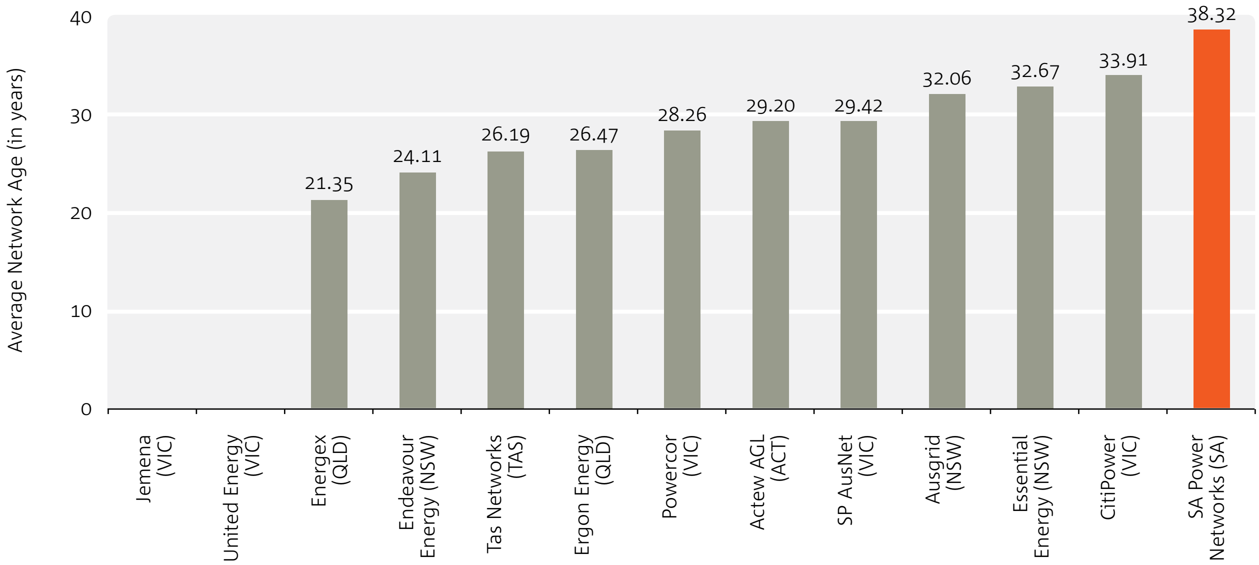
In response to our 2010 Determination, the changing safety environment and the consequential evolution of good electricity industry practice, SA Power Networks has been continually improving our asset management practices and systems. A major part of that improvement has been the continuation of the transition from a replace-on-fail approach to a replace-before-fail approach for our more critical assets, known as 'priority assets'. This approach requires good asset condition data and the use of improved analytical techniques that allow us to assess the risks of asset failure and better enable prudent replacement.

The need for prudent and effective asset management has been brought into sharp focus by recent events such as the 2009 Victorian bushfire disaster and serious incidents in Western Australia in 2003, 2009 and 2013. These events have provided a greater realisation across the industry of the significant safety risks posed by defective network assets in sensitive areas. In addition, the reviews that were undertaken following the occurrence of these events and the resulting recommendations must now be considered when determining:

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

These events have increased the community, legal and industry focus in this RCP on ensuring that risk-based approaches to managing defects and determining replacement requirements have a greater emphasis on achieving compliance with safety regulations and associated technical standards.

Figure 20.8: Average Australian distribution network ages



Notes
– Data is sourced from AER Category Analysis Regulatory Information Notices (**RIN**) data, published 25 June 2014.
– Category Analysis data supplied to the AER by Jemena was in the incorrect format and has therefore been excluded from this analysis.
– Category Analysis data supplied to the AER by United Energy was inclusive of disposed assets and has therefore been excluded from this analysis.

SOURCE: SA POWER NETWORKS ANALYSIS 2014

SA Power Networks has undertaken a number of initiatives to improve our overhead line inspection and defect identification processes, including:

- requiring all asset inspectors to be accredited to UET20612 Certificate II in Electricity Supply Industry (**ESI**) — Asset Inspection standard;
- taking reasonable steps to improve our overhead line inspections by increasing the frequency of asset inspections in line with our 2010 Determination, particularly in high corrosion zones and in high bushfire risk areas;
- by developing and implementing mobile data technology so that inspectors better collect defect and asset condition information; and
- applying an increased level of diligence, prudence and foresight to the auditing of our asset inspection activities to achieve consistency of inspections.

The early part of the current RCP was focussed on enhancing the quality of asset inspections through the training of inspectors and the development and implementation of the supporting systems. With the progressive increase in asset inspections over the current RCP, we have identified a significant increase in the volume of identified asset defects. The volume of identified defects, and consequential replacement activity, is significantly above the AER-approved allowance in its 2010 Determination for this work and exceeds SA Power Networks' expectations at the time of making the 2010–15 Proposal.

During the 2010–15 RCP, SA Power Networks substantially increased our asset replacement expenditure to address the highest risks associated with the increasing volume of identified asset defects and to discharge our duty to take reasonable steps to ensure that our distribution system was safe and was safely operated. We have reallocated capital funds to replacement work (60% more than AER allowance) to address those assets that presented the most immediate risk to public safety, property and to our network.

Notwithstanding the increased expenditure, we are seeing an escalating increase in the network risks during this period which well exceed the historical levels of risk on which our SRMTMP is based.

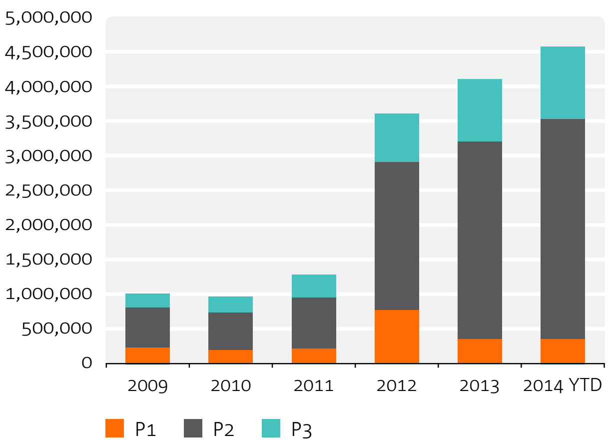
The level of network risk the business carries is calculated by using the Maintenance Risk Value (**MRV**) methodology. The MRV is calculated for all inspected power line assets. MRV reflects the risks associated with the measured condition of the asset and the asset's criticality. The calculated MRV of an inspected asset is a critical parameter that we use to grade the severity of the defect and define the timeframe for any remediation actions, consistent with the SRMTMP. The method for determining the MRV is further defined in our Network Maintenance Manual and Line Inspection Manual which has been incorporated by reference into our ESCoSA-approved SRMTMP, and also provided at Attachment 7.2.

The MRV of the defect is significantly influenced by the probability of failure and severity of defect, and to a lesser degree by other factors (further information on calculating the MRV is contained in Section 9.4 and 9.8 of the Line Inspection Manual (Attachment 20.11)). Defects and their management are graded as follows, based upon their MRV:

- P1 — Defects with a MRV of 190 or greater are classified urgent (P1) as they pose a significant/likely risk to safety or interruption to supply. These defects should be rectified within 28 days.
- P2 — Defects with a MRV of between 90 and 189 are classified non urgent (P2) as no plant failure has occurred but there is potential to deteriorate/fail. These defects should be rectified within 180 days.
- P3 — Defects with a MRV of between 50 and 89 are classified unlikely (P3) to fail but degradation may slowly continue. These defects should be rectified within 720 days.
- P4 — Defects with a MRV of between 1 and 49 are classified for ongoing condition monitoring.

Given the increasing volumes of asset defects being detected via our improved asset inspection processes, the recorded MRV has increased significantly during the current RCP as shown in Figure 20.9. This increase is likely to continue over the initial years of the 2015–20 RCP as our improved asset inspection process extends to cover more and more of our ageing distribution system, requiring us to take reasonable steps to ensure that the risk level is returned to acceptable historic levels.

Figure 20.9: Power line maintenance risk value for 2009 to 2014



SOURCE: SA POWER NETWORKS ANALYSIS 2014

20.5.3 Proposed capital expenditure for asset replacement for 2015–20 RCP

This section outlines the network operating environment, provides an overview of the methodologies used to forecast the amount of the proposed capital expenditure for replacement of assets and the associated network risks being addressed as reflected in the change to the existing MRVs.

In considering the rationale, business drivers and customer support for investment in asset replacement, this chapter should be read in conjunction with Chapters 9 'Keeping the power on for South Australians' and 11 'Responding to severe weather events' and the referenced attachments.

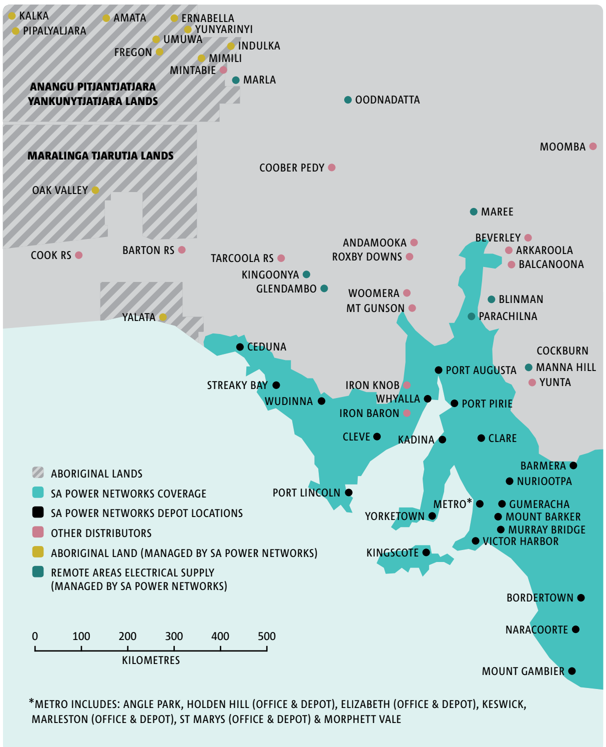
Detailed discussion of major categories of assets in our asset replacement program is provided as follows:

- Power lines — Section 20.5.4;
- Substations — Section 20.5.5;
- Telecommunications — Section 20.5.6; and
- Safety — Section 20.5.7.

Network operating environment

In developing our forecast for the 2015–20 RCP we are seeking to prudently manage the return of our asset portfolio risk to acceptable levels that are required for compliance with our regulatory obligations under the approved SRMTMP. This means that asset defects will be remediated in the timeframe approved in our SRMTMP. The primary reason to return our risk to historical levels is our heightened concern that the structural failure of an asset could result in damage to people, property or the network. That is, public safety risk (direct impact or electric shock following structural failure is deemed to be more significant in more densely populated urban areas) and bushfire risk (asset failure causing bushfires particularly in High Bushfire Risk Areas (**HBFRAs**)).

Figure 20.10: SA Power Networks' service area



SOURCE: SA POWER NETWORKS

The level of risk in our network is dependent on the asset location and the level of bushfire risks and corrosion risks at that location. SA Power Networks operates an extensive overhead power line network to supply electricity reliably and safely to its customers. Figure 20.10 illustrates the expanse of our overhead line network in South Australia. The network is centred on Adelaide and supplies electricity to the south-east coastal region of South Australia and up towards inland South Australia.

As can be seen in Figure 20.10, SA Power Networks' overhead power line network is predominantly situated along the coast which is constantly exposed to the saline environment. As a consequence, corrosion of the network is a major cause for concern to SA Power Networks. We have acknowledged the impact of corrosion on the assets in the overhead power line network, including poles and conductor, by identifying the corrosion zones in South Australia. Figure 20.11 details the levels and location of the atmospheric corrosion zones in South Australia.

There are three levels of corrosion zones: low; severe; and very severe. The severe corrosion zones extend further inland than the very severe corrosion zones due to the transfer of airborne salts by the atmosphere. Comparing Figure 20.10 with Figure 20.11 identifies that a large proportion of the distribution network is located in the severe and very severe corrosion zones.

South Australia has several natural reserves and conservation parks that are protected, along with forestry plantations, which our distribution network intersects. Operating the distribution network in forested areas poses risk of bushfire. We have recognised the importance of minimising any risk associated with operating the distribution network in the protected natural environment by identifying the levels and location of bushfire prone areas. Figure 20.12 illustrates the three bushfire risk areas in South Australia.

The areas identified are high bushfire risk areas (**HBFRAs**), medium bushfire risk areas (**MBFRAs**) and non-bushfire risk areas (**NBFRAs**). High bushfire risk areas include most of the protected natural reserves and conservation parks, and forestry plantations. Medium bushfire risk areas reflect the risk to developments on the fringe of dense bushland. This area consists of metropolitan, suburban, and country districts.

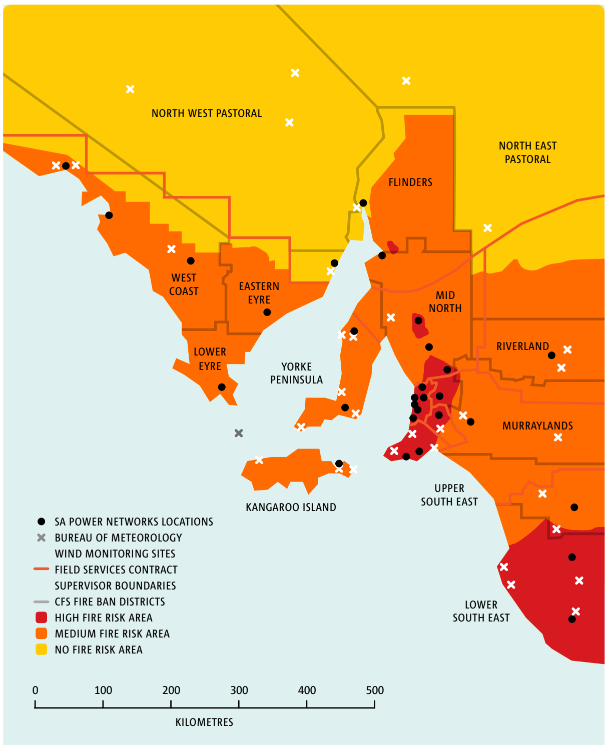
In order to effectively manage our asset portfolio, SA Power Networks specifies the corrosion zone level and the bushfire risk area category for each asset in the Asset Management Database.

When comparing all three Figures 20.10, 20.11 and 20.12, it can be identified that significant portions of our distribution network are located in both very severe corrosion zones and high bushfire risk areas, which presents a significant risk given the age and deteriorating condition of our asset portfolio. Adding to our concerns is that the Australian Bureau of Meteorology (**BoM**) predicts the trend of increasing severity and numbers of extreme weather events and high fire risk days that we have been experiencing in the current RCP is likely to continue (refer Attachment 10.1, Climate extremes analysis for South Australian Power Networks operations, The Australian Bureau of Meteorology, 2014).

Figure 20.11: Atmospheric corrosion zone map of South Australia

SOURCE: SA POWER NETWORKS

Figure 20.12: Bushfire risk areas in South Australia



SOURCE: SA POWER NETWORKS

Figure 20.13: Forecasting methodologies

	CBRM	Topdown	MVDFM*	Targeted	Historic trend	Repex**
Power line						
Poles	●	○	○		○	○
Conductor	●	○	○		○	○
Other power line				○	●	○
Substation						
Transformers	●	○		●	○	○
Circuit breakers	●	○		●	○	○
Other		○		○	○	○
Telecommunications				●	●	○
Safety				●	●	○

● Indicates forecast basis per asset class (selected methodology)
○ Methodology used

* The multivariable defect forecasting model (**MVDFM**) is an internally developed bottom up forecasting model. This model has been verfied by an independent party, Huegin.
** Repex is not used for all asset classes, only those with asset specific age profiles and replacement history, eg it is not used for bundled assets such as pole tops.

SOURCE: SA POWER NETWORKS ANALYSIS 2014

Asset replacement forecast
In developing our forecast for the 2015–20 RCP we are seeking to prudently manage the return of our asset portfolio risk to the level that is required for compliance with our regulatory obligations under the SRMTMP, as agreed with the OTR. The primary reason to return our risk to historical levels is our heightened concern that the structural failure of an asset could result in damage to people, property or the network. That is, limiting the potential for public safety risk (direct impact or electric shock following structural failure is deemed to be more significant in more densely populated urban areas) and for bushfire risk (asset failure causing bushfires particularly in HBFRAs).

Our customers have strongly supported an appropriate level of investment in replacing and refurbishing assets as discussed above in Section 9.3.1. With reference to the key Customer Engagement Program insights shown in Section 6.2.3, we aim to:
- continue asset management and investment to drive reliability, (and) manage risk; and
- prioritise preventative maintenance to mitigate risk.

We have also addressed the concern raised by the AER in its 2010 Determination regarding the need for consistency in the application of our risk framework to assessments across all asset classes and asset management plans (**AMPs**).

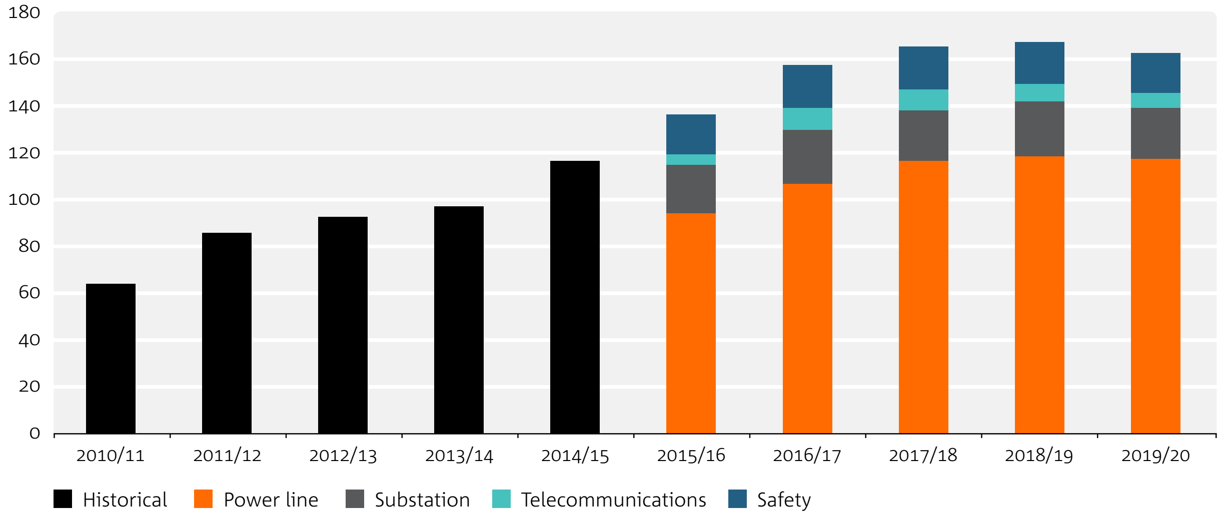
To ensure robust expenditure profiles are developed, wherever possible we have applied multiple methodologies in the development of our forecasts, particularly for our priority assets[56]. Figure 20.13 shows the range of methodologies applied for each of the asset categories. The AER's Repex model has been used as a comparison methodology in all possible cases (although it is not suitable for use in every circumstance). Depending on the operational environment for the asset category, the asset data available and the type of analysis most appropriate to the particular asset category, we identify the preferred methodology for a particular asset.

'Targeted' analyses refer to special cases where specific operational circumstances require tailored approaches to development of (generally limited) forecast programs.

For detailed analysis of the model outputs and comparison to the AER Repex model refer to the respective asset category AMPs. In addition for the pole asset category, refer to Attachment 20.15 Pole Replacement — Expenditure Justification.

56 Our priority assets consist of poles, conductor, substation transformers and circuit breakers.

Figure 20.14: Replacement expenditure by key components (June 2015, $ million)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Table 20.7: SA Power Networks' forecast asset replacement expenditure for the 2015–25 RCPs (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Replacement	134.0	155.9	166.0	169.2	166.9	160.0	159.4	157.0	154.0	156.2

In conjunction with the introduction of the CBRM model, SA Power Networks has implemented a field data capture program to collect condition information on our priority assets, enabling a forecast approach that accurately factors in many asset variables such as age, defect history and physical conditions. Priority assets are those asset sub-categories that represent a significant portion of the SA Power Networks' asset base, capital expenditure requirements and/or risk. For power lines, poles and conductors are priority assets, and for substations, power transformers and circuit breakers are priority assets. Together, these assets represent approximately 50% of the total asset replacement capital expenditure forecast.

Our Condition Monitoring and Life Assessment (**CM&LA**) plan (AMP 3.0.01, Attachment 9.1), that incorporates our condition monitoring program has enabled us to develop a prudent and economically efficient 2015–20 RCP replacement capital expenditure forecast that will manage the forecast level of network asset defects while meeting our regulatory obligations and progressively moving network risks back to levels acceptable to the business 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 (Section 60(1) of the Electricity Act).

Figure 20.14 shows SA Power Networks' total replacement historic and actual capital expenditure forecast for the 2010–15 RCP, along with the total replacement forecast capital expenditure that we consider will be required during the 2015–20 RCP in order for us to achieve the capital expenditure objectives described in Section 20.1 of this chapter.

Table 20.7 outlines the asset replacement expenditure for the 2015–20 RCP of $792.0 million. We have included indicative 2020–25 RCP capital expenditure forecasts to show our expenditure over the longer term.

SA Power Networks has modelled the impact of this asset replacement expenditure over a 10 year timeframe (refer Figure 20.15). The figure shows MRV values attached to actual and forecast distribution power line defects 'raised' (ie identified by asset inspections), compared to those 'fixed' (ie rectified by asset replacement works), with the 'outstanding' trend line indicating the remaining MRV of the aggregated unrectified defects. The proposed asset replacement expenditure over the next 10 years will deliver a significant positive impact on the MRV outcomes.

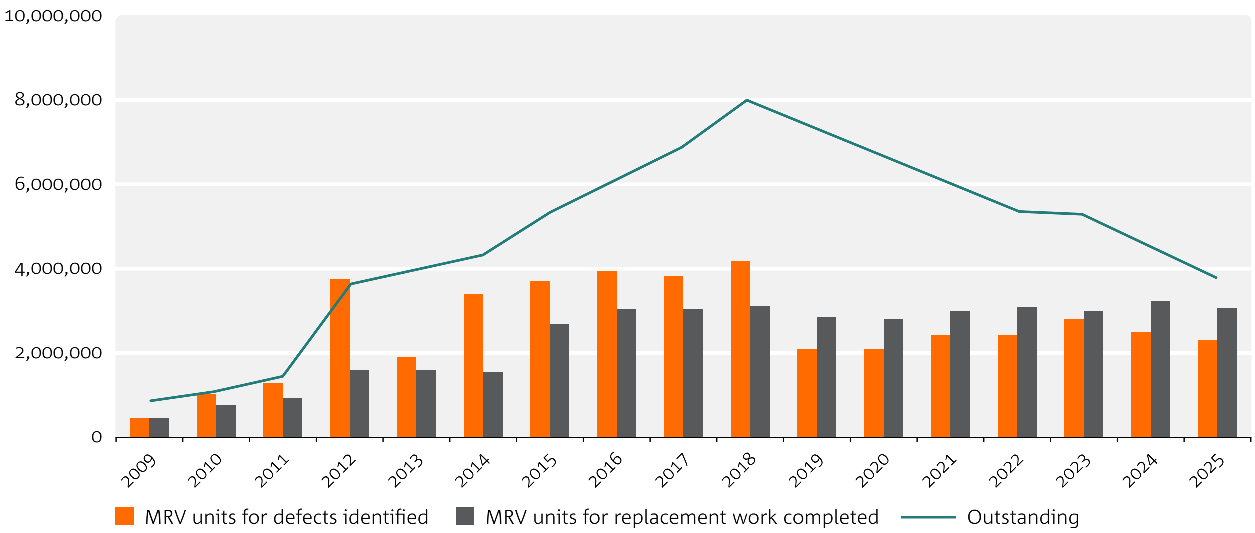
Figure 20.16 outlines the network risk impact that would result if the level of capital expenditure was maintained at current 2014 levels. SA Power Networks considers that this is not an acceptable position as it is not consistent with the regulatory obligations to maintain a safe electricity distribution system and would not address the concerns and expectations that customers have made known during our Customer Engagement Program.

The following sections provide further details with respect to proposed asset replacement capital expenditure for the AER subcategories of power lines, substations, telecommunications and safety.

In line with the importance of the priority assets within the power lines and substations categories, we discuss priority asset sub-category background, failure modes, condition assessments, applicable forecasting methodologies, the optimal forecasting methodology and the long term (10 year) expenditure forecast.

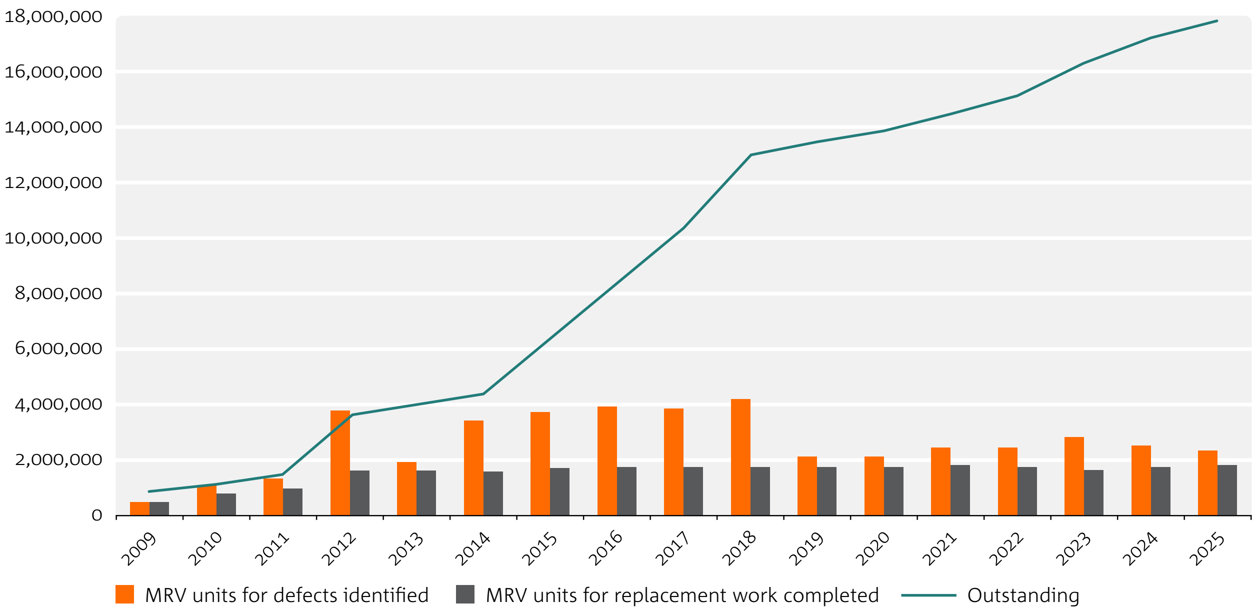
For other asset sub-categories, we provide summary explanatory information, including 2010–15 RCP outcomes where relevant, and the five year 2015–20 RCP expenditure forecast. Detailed discussion for these assets is generally consigned to the relevant AMP as identified in the sub-category discussion.

Figure 20.15: Total power line MRV profiles with proposed 2015–20 RCP program (MRV units)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Figure 20.16: Total power line MRV profiles with continuation of 2014 replacement expenditure levels (MRV units)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

20.5.4
Power lines

Power lines consist of overhead network, underground network and all associated distribution transformers, power line protection and switching devices. The major asset replacement expenditure items in the power line category are pole replacement and refurbishment, and conductor replacement. The total forecast capital expenditure for power lines in the 2015–20 RCP is $553.8 million (June 2015, $).

Poles replacement and refurbishment

Background

Stobie poles are unique to South Australia and have been used to support overhead distribution lines for 90 years. They were introduced due to a lack of suitable timber within the State and other than metrification, Stobie poles have remained largely unchanged as they are a well proven product.

Stobie poles consist of a concrete core with two outer steel beams connected by bolts to ensure strength. The poles are symmetrically tapered at both ends to ensure that maximum width and bending strength requirements occur just below ground level. Footings incorporating reinforced concrete are used to ensure that poles are securely anchored in the ground. Sizes of Stobie poles may vary from 9m in length for low voltage applications to greater than 15m for sub-transmission applications.

Whilst the initial cost of installing a Stobie pole is greater than its timber equivalent, they well exceed the life of timber poles. The service life of Stobie poles has been assessed as between 30 and 90 years depending upon the corrosive conditions of the installed location.

The first Stobie poles were installed in 1924, and an assessment of the current age profile indicates that the majority of poles have been installed for between 30 and 60 years. Due to this longer life, historically we were not seeing a significant number of pole failures and, the planned replacement of poles had not been of great concern to us. But the ageing of the network means we have been transitioning into the replacement cycle and so the need to replace poles has been increasing over recent years.

SA Power Networks' SRMTMP, approved by ESCoSA on the recommendation of the OTR, includes an inspection regime with associated defect rectification standards. The period between inspections, known as the inspection cycle, is set to reflect the risks associated with pole failure. That is, poles in a higher risk environment have a shorter inspection cycle than those in a lower risk environment.

For the purpose of defining the appropriate inspection cycle, we classify our poles based upon two parameters that reflect the location of the poles:

- the corrosion zone, which reflects the rate of corrosion we may expect given the environmental conditions. This is graded as either low (CZ1), severe (CZ2) or very severe (CZ3), refer to Figure 20.11 above; and
- the bushfire risk zone, which is graded as a high bushfire risk, medium bushfire risk, or no fire risk, refer to Figure 20.12 above.

In the 2010–15 RCP, SA Power Networks received additional funding from the AER to perform more detailed and more frequent asset inspections, in particular in severe and/or very severe corrosion areas where the inspection frequency has been increased to five years from 10 years previously.

The more detailed and frequent asset inspection program has collected more asset condition data than was previously available and has resulted in the identification of a large volume of pole defects requiring rectification. The increased number of defects has resulted in an escalating MRV since 2011/12 as shown in Figure 20.16. As the asset inspection cycle for all poles in NBFRA will not be completed until 2018 we fully expect to see the number of defects and the MRV continue to grow.

With the additional information on asset condition that is now available SA Power Networks is able to better target our highest risk asset defects for prioritisation of work.

Failure modes

Ground level corrosion is the main failure mode for Stobie poles. The rate of ground level corrosion varies depending on the pole corrosion zone. In the low corrosion zone the above ground corrosion tends to be lower which results in a higher proportion of poles being suitable for refurbishment than replacement. Refurbishment can be achieved by welding steel plates across the corroded section (pole plating), refer to Images 20.1 and 20.2. We consider refurbishment the most prudent and efficient option as the cost is approximately 15% of replacing the pole and can extend pole life up to 50%.

Image 20.1: Corroded Stobie pole

Image 20.2: Steel plating of a Stobie pole

In the moderate and high corrosion zones the proportion of poles refurbished in favour of replacement is likely to be less because above ground corrosion of steel elements becomes more prevalent. In addition, corrosion and distortion of concrete-embedded anchor bolts leads to losses/spalling of the concrete. Therefore we replace poles in those cases where pole plating is not an option, for example, where there is severe corrosion along the length of outer steel beams or if a pole had been plated previously.

The end of life of a pole is determined by the extent of corrosion, both above ground and at ground level. Reaching this end of life standard, as defined in the Line Inspection Manual, does not mean that the pole will fall over, rather that the strength is diminished and there is a high probability that the pole strength will be insufficient under expected high mechanical load conditions. That is, the remaining strength of the corroded pole is such that it can no longer safely operate in its physical environment as required by the Electricity (General) Regulations.

Condition assessment
Pole failure is considered to be when the corrosion standard is exceeded rather than when the pole falls. On average around 11 HV poles, and up to 25 LV poles, have fallen per annum (since 2003) due to the effects of severe corrosion and generally during strong wind conditions.

A pole that fails and falls can have public safety, reliability and environmental consequences. Bushfire starts are the most significant consequence of a pole falling.

Figure 20.17 profiles the cumulative impact of actual and pole defects raised compared to those fixed for the period to May 2014. Figure 20.17 clearly identifies the network risk impact that would result if the level of capital expenditure for poles was maintained at current levels. As a result of the increased understanding of the quantity of defects and the resultant unacceptable increased risk to the business, SA Power Networks increased the number of pole interventions in the current RCP to address priority maintenance for P1 defects, as can be seen in Figure 20.18.

Forecasting methodologies
We have undertaken an assessment of the level of pole replacement and refurbishment work using multiple methodologies as follows:

- independent top down forecast undertaken by AECOM;
- CBRM model forecast developed by EA Technologies;
- MVDFM developed internally;
- historical trend — extrapolation of historical trends in numbers of replacements and spend; and
- AER Repex model.

The AECOM replacement model provides a high level (top down) forecast that considers estimates of planned (prioritised by age based risk) replacements each year. The intention of this program is to hold the current risk profile (and level of service) constant. While endeavouring to quantify and prioritise replacements based on asset risk, the model is not fine enough to model specific risk, forecast asset performance, nor model replacement scenarios.

The AER repex model provides a very high level (top down) modelling approach that considers asset age, asset life statistics and historical expenditure to forecast future replacement volumes and expenditure requirements. Forecasts do not directly factor in aspects of condition, criticality or risk, nor differentiate between planned and unplanned (failure) replacement types. Replacement life within the model is used as the proxy for all factors that drive asset replacements, under the assumption that current replacement strategies and practices will remain static into the future. As the approach relies on overarching population information only, the model does not directly allow deeper analysis of asset performance, condition trends, future risk nor changes in asset management drivers.

SA Power Networks considers the two most prudent forecasting models are the Condition Based Risk Management approach from EA Technologies and the internally developed model, known as the Multi Variable Defect Forecasting Model (**MVDFM**).

The CBRM model bases its expenditure forecast on the Health Index rating which is a score assigned to each pole based on the age, condition and other factors affecting the working life. The Health Index is calculated in several stages (initial HI1, intermediate HI2 and final HIY0) and is then used to calculate the probability of failure under various scenarios. Together with measures of the consequence of failure and criticality, this gives a measure of the inherent risk in the network. Although the CBRM model has alternative modes, the replacement expenditure is typically set to a level that maintains the current level of risk.

The internally developed MVDFM is based on historical defect data. The model produces forecasts of the expected number of defects and expected rectification cost per defect for each location, corrosion zone and voltage level. These factors combined give a forecast of the total replacement expenditure. The forecast is calculated for the next 10 year period.

We believe it is prudent to manage the risk of pole structural failure to enable us to progressively manage the risk within our network so that the overall level of risk can be returned to acceptable levels consistent with the SRMTMP, over the next two regulatory control periods.

While the CBRM and MVDFM forecasting methods use very different approaches, they have both been applied in a way that forecasts a required level of expenditure to ensure that the level of risk as envisaged by the approved SRMTMP is maintained. The internal model addresses defects as they arise, whereas the CBRM approach aims to intervene to reduce the probability and consequence of risks associated with failure.

All of the forecasting methodologies derived comparable results for pole replacement, with the exception of the AECOM forecast. The AECOM forecast was considerably lower than the other methodologies because the analysis is based on generalised data on environmental conditions, with no ability to calibrate for known defects or other individual asset specific information. For reasons explained previously, SA Power Networks' historical replacement rate for poles has been well below the required replacement levels to maintain our network in accordance with our SRMTMP, therefore the results from the AECOM model are not representative for the poles asset class.

Figure 20.17: Identified pole defects vs rectification and the resultant outstanding defects in the current RCP

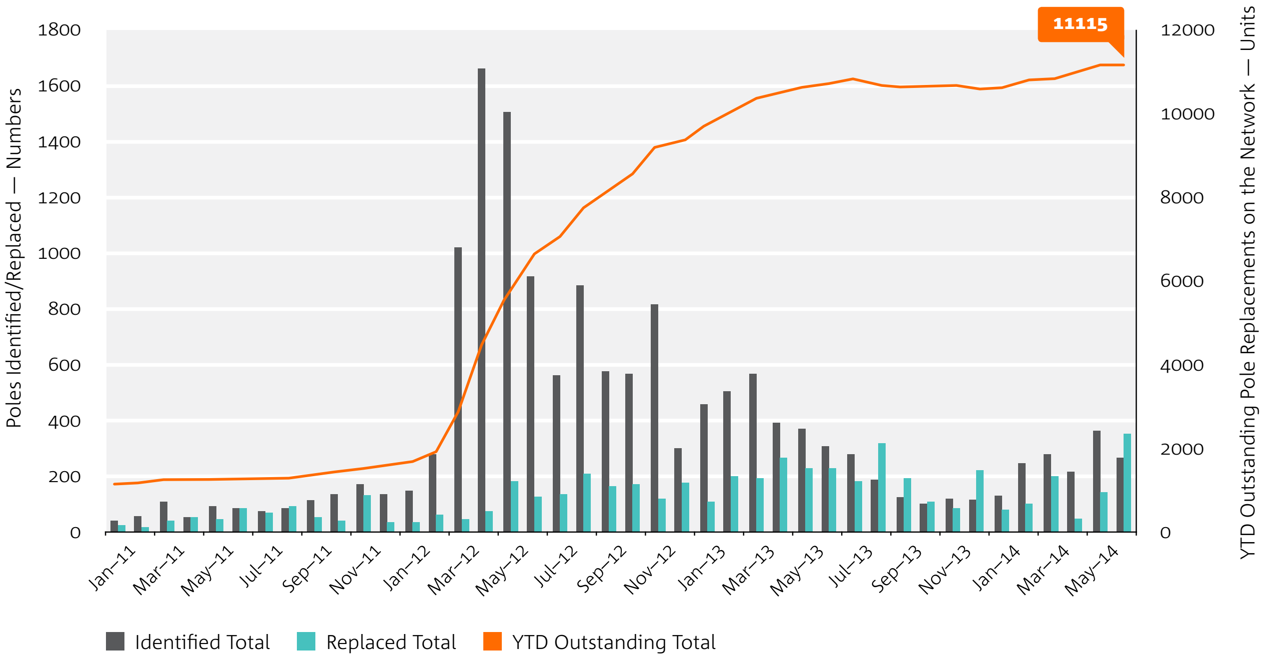
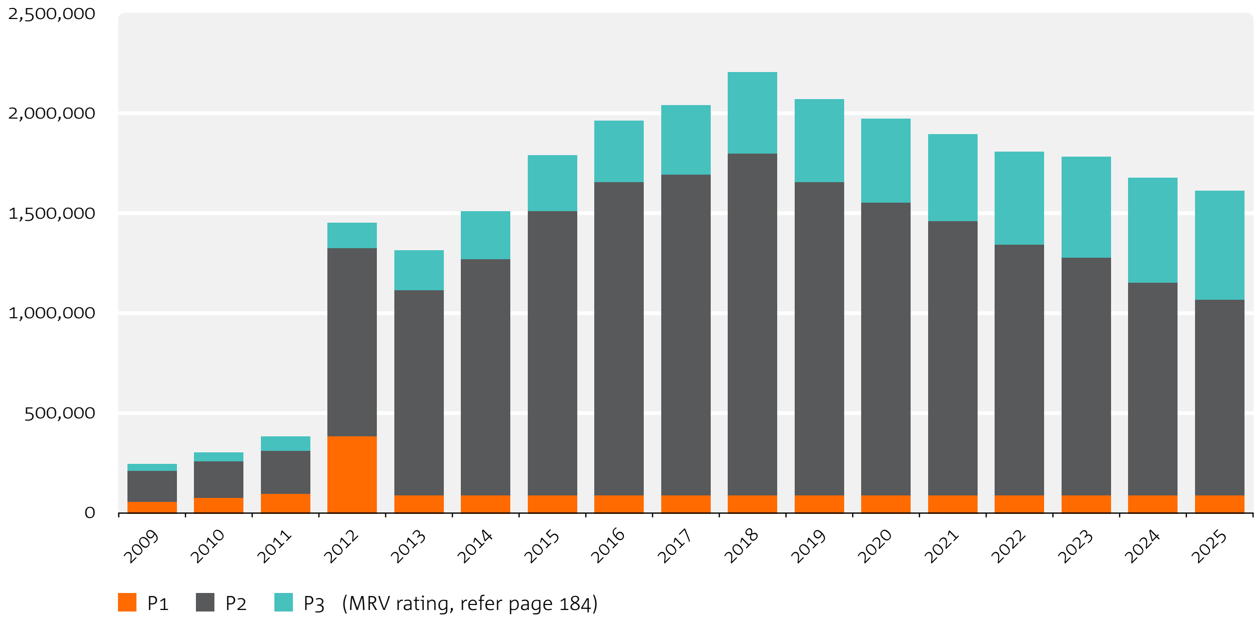


Figure 20.18: Maintenance Risk Value for 2009 to 2025 — Stobie poles



The preferred forecast method adopted by SA Power Networks for the replacement and refurbishment capital expenditure for the pole population, is the CBRM approach. The CBRM approach is preferred because of its granularity as specific poles are identified for replacement. As well as being a risk based approach, the CBRM model has a number of advantages as a forecasting tool:

- It forecasts risk as the monetised value of potential loss;
- It is used by numerous Distribution Network Service Providers; and
- It has been specifically calibrated and tested by EA Technologies for the SA Power Networks pole population.

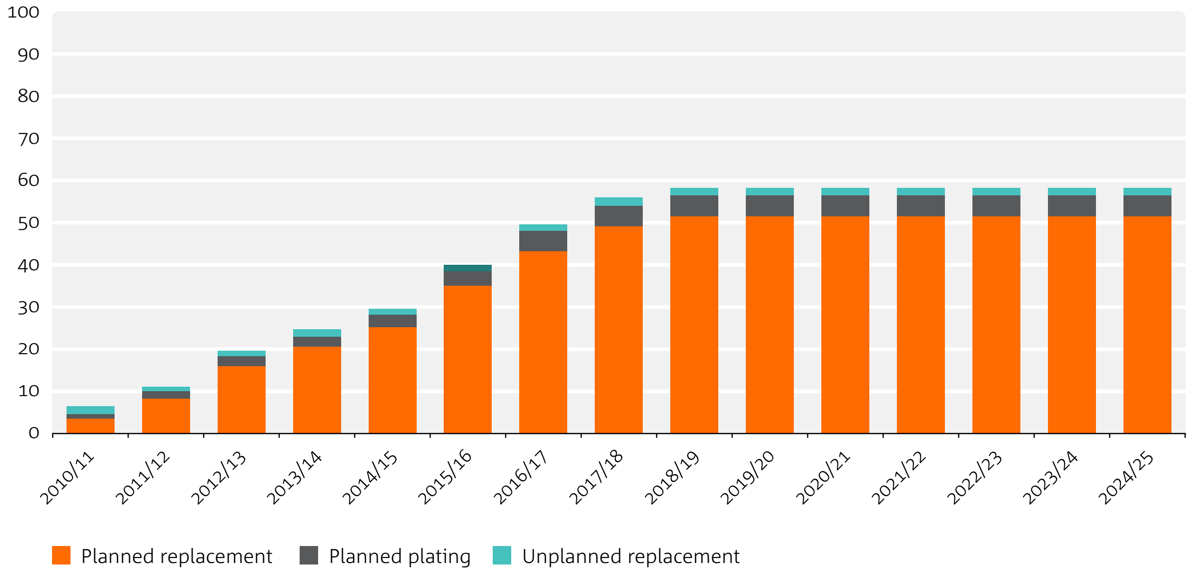
We have used the AER's Repex model to validate our pole replacement forecast. For this analysis, we used the age profiles advised to the AER in our category analysis RIN data.

Expenditure forecast

The poles replacement and refurbishment capital expenditure forecast is based on pole age, condition and location and is produced in accordance with our CM&LA plan described in AMP 3.0.01 and our Poles AMP 3.1.05. The pole replacement and refurbishment forecasts are summarised below. For a more detailed explanation of the methodologies and analysis of our poles program, refer to Attachment 20.15 Pole Replacement — Expenditure justification.

The total forecast for pole replacement for the 2015–20 RCP is $238.9 million and pole refurbishment is $23.4 million (June 2015 $). The historic and forecast replacement expenditure profile is shown in Figure 20.19. At approximately 15% of the cost to replace a pole, pole refurbishment (pole plating) is a means of efficiently extending pole asset life and is the preferred alternative to pole replacement wherever feasible. The ratio of forecast pole replacement numbers versus pole plating numbers is approximately 50:50.

Figure 20.19: Historic and forecast pole replacement and refurbishment expenditure profile (June 2015 $ million)



Conductor replacement

Background

The route length of overhead power lines is commonly used to measure the size of our overhead network. The route length of a line is based on the distance between the first and last tensioned structures supporting the overhead line. The total route length of the overhead network as recorded in the Asset Management Database is 63,610km[57]. Figure 20.10 above details our network coverage in South Australia.

The age profile of SA Power Networks' overhead network is varied. There was a significant increase in the route length of overhead power lines during the period 1955 to 1977. The average age of SA Power Networks' overhead power lines network is 49 years, with many of the power lines installed in the years 1955, 1956, 1958 and 1966. Approximately 54% of the overhead power lines are greater than 50 years; conversely 7% of overhead lines are less than 20 years old.

SA Power Networks' overhead power line network consists of both sub-transmission and distribution voltages that range from 66kV to 240V. The specific voltages used in the network are listed below.

Distribution voltages:

- Overhead low voltage distribution (415V or 240V);
- Overhead high voltage 11kV;
- Overhead high voltage 33kV (used as distribution voltage to directly supply customers);
- Overhead Single Wire Earth Return (SWER) (19kV); and
- Overhead other distribution voltages (7.6kV).

Sub-transmission voltages:

- Overhead sub-transmission 33kV; and
- Overhead sub-transmission 66kV.

The majority of power lines installed during 1930 to 1949 are 33kV power lines, while the majority of power lines installed in 1955, 1956, 1958 and 1966 are SWER and 11kV power lines. To a lesser degree, low voltage, 33kV and 66kV power lines were installed throughout 1950 to 1979. In the past 20 years, SWER lines were the most commonly installed, followed by 11kV and 33kV power lines.

Failure modes

There are several conductor failure modes. Two of the most common failure modes of overhead conductor are corrosion and fatigue. Overhead power lines in various corrosion zones are prone to different rates of conductor degradation. The corrosion zone map is shown in Figure 20.11 above.

The identification of one failure mode can also signal other impending or active failure modes. For example, the pitting in conductor strands due to corrosion may increase stress; this in turn magnifies the effect of wind induced vibrations in the remaining conductor strands. Consequently, a conductor exposed to a corrosive environment is prone to fatigue at a higher rate than one that is not in a corrosive environment.

Condition assessment

Of the 63,610km (route length) of overhead lines registered in SA Power Networks' Asset Management Database, 53% of power lines are in the low corrosion zone, 35% of power lines are in severe corrosion zone, and the remaining 12% are in the very severe corrosion zone. It is important to highlight that whilst the majority of the power lines in low and severe corrosion zones reside in medium bushfire risk areas, the majority of the power lines in the very severe corrosion zones are located in high bushfire risk areas and have the least corrosion resistant conductor types (ie ACSR and steel), representing a significant risk.

It is difficult to assess the condition of conductors and produce a reliable estimate of the likelihood of failure. However, it is known that all the failure modes can be induced through the effect of ageing. Therefore, in addition to the indicators stated above, the age of a conductor is considered when assessing the potential for conductor failure. The average life expectancy of overhead conductors is shown in Table 20.8.

Table 20.8: Overhead conductors useful life by corrosion zone

Corrosion Zone	ACSR Group	Aluminium Group	Steel Group
Low (1)	70	80	73
Medium (2)	56	66	60
High (3)	35	45	50

Note: Aluminium Conductor Steel Reinforced (**ACSR**)
SOURCE: SA POWER NETWORKS

57 Note, total conductor length (including sag) is approximately 71,000 km.

MRV represents the level of risk associated with defects that could, within different timeframes, lead to conductor failure. While Figure 20.20 indicates the recorded MRV for conductors has only marginally increased during the 2010–15 RCP, it is important to highlight the MRV forecast is based on historical defect data. Through our asset inspections we are obtaining improved data on the condition of conductors and our MRV based on this historical data is likely to significantly understate the inherent risk level.

Forecasting methodologies

We have undertaken an assessment of the level of conductor replacement using multiple methodologies as follows:

- Independent top down forecast undertaken by Aurecon;
- CBRM model forecast developed by EA Technologies;
- MVDFM developed internally;
- Historical trend — extrapolation of historical trends in numbers of replacements and spend; and
- AER Repex model.

An explanation of the forecasting methodologies is provided in the poles section above, with the exception of the Aurecon methodology.

Similar to the AER's Repex model, Aurecon's approach models conductor as aggregate populations. Its primary asset inputs are age profiles and unit costs, and it uses asset lives[58] to predict failures (or replacement needs).

The model produces an annual profile of replacement volumes for these classifications over a 10 year period using the asset age and asset life. This annual profile is then averaged to produce the main output volume forecast[59].

All of the forecasting methodologies derived comparable results for conductor replacement, with the exception of the Aurecon and CBRM forecast. The Aurecon forecast was considerably lower than the other methodologies because the analysis is based on historical replacement rates and generalised data on environmental conditions, with no ability to calibrate for specific asset classes or known defects. For reasons explained previously, SA Power Networks' historical replacement rate for conductors has been well below the required replacement levels to maintain our network in accordance with our SRMTMP, therefore the results from the Aurecon model are not representative for the conductor asset class.

When considering which forecasting approach may be appropriate for conductors, it is important to note that we do have a good understanding of our conductor asset base. Given the comprehensive data we have available, the preferred forecast methodology adopted by SA Power Networks for the replacement capital expenditure for conductors is the CBRM approach. The CBRM approach is preferred because of its granularity, as specific lengths of conductor are identified for replacement. This type of methodology and model has been used successfully elsewhere for both asset management and regulatory forecasting purposes. As such, we consider it a suitable approach for our circumstances.

The CBRM forecast was considerably above the other methodology forecasts because we have replaced very little conductors historically and we have a significant amount of conductors located in high corrosion zones. However, it would be unrealistic for SA Power Networks to deliver the level of replacement that the CBRM model predicted for conductors, therefore the model was calibrated to enable a more deliverable program.

The forecast method can be characterised as a 'delivery-adjusted CBRM model'. In this regard, a CBRM model has been used to prepare a base volume and expenditure forecast to 2025. However, the CBRM model developed by EA Technologies does not allow for delivery constraints that can occur if the expenditure step increase is too large from one year to the next.

Therefore, where the CBRM model predicts a significant step up in replacement levels, we have profiled the CBRM model output to represent what we believe would be the prudent and efficient delivery profile.

The AER developed Repex model has been used as our primary approach to validate our conductor forecast. In order to develop the forecast in the Repex model, we have calibrated the model parameters in the manner that we understand the AER will apply to that model.

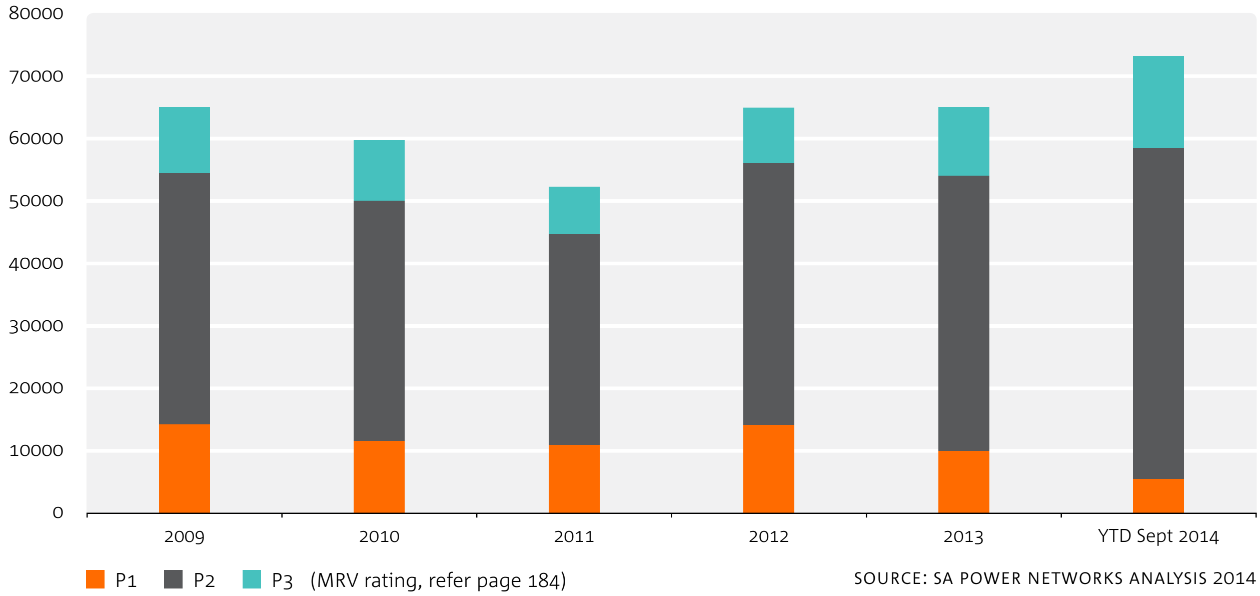
Figure 20.21 shows the Repex forecast capital expenditure with the orange line showing our delivery-adjusted CBRM model results for comparison.

The AER Repex model forecast is above our CBRM forecast. Therefore, this supports a view that our forecast is not overstating the replacement required to maintain the performance of our network over the next regulatory period.

58 Unlike the AER's Repex model, the Aurecon model uses a deterministic life model (ie assets are replaced when they exceed this life).

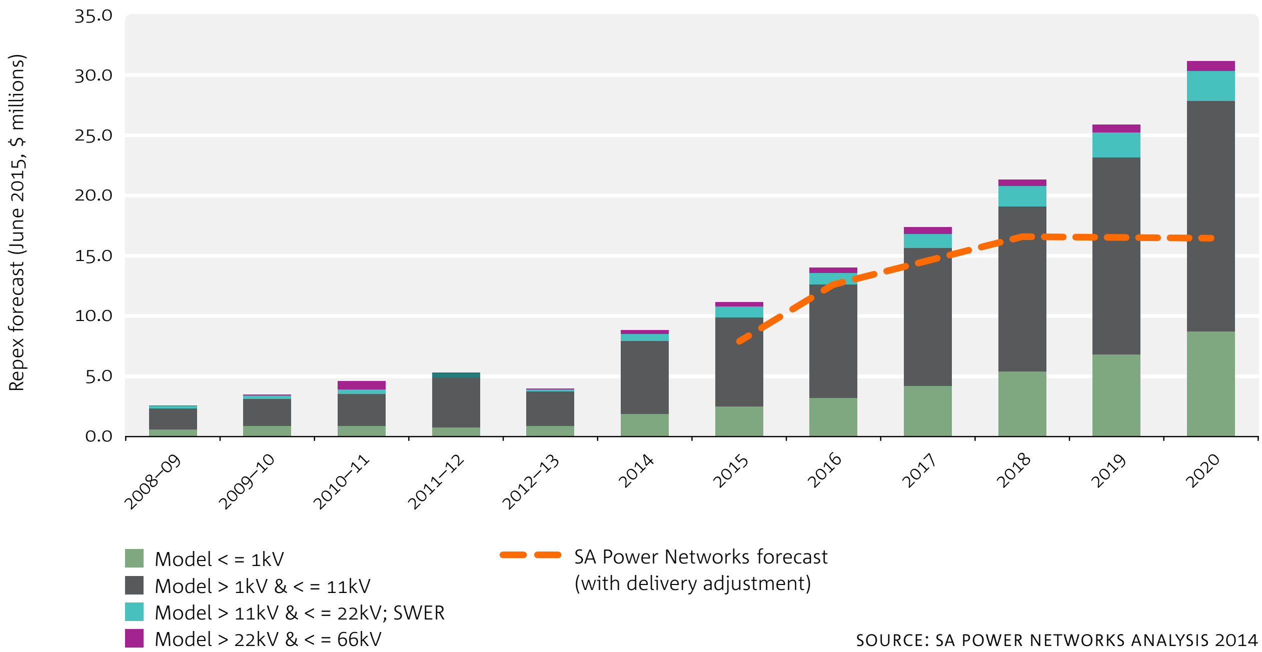
59 This averaging is considered appropriate because of the deterministic life model, which can produce quite variable replacement results year-on-year, reflective of the shape of the age profile.

Figure 20.20: Maintenance Risk Value for 2009 to 2014 — conductor



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Figure 20.21: Conductor Repex model capital forecast expenditure analysis (June 15, $ million)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

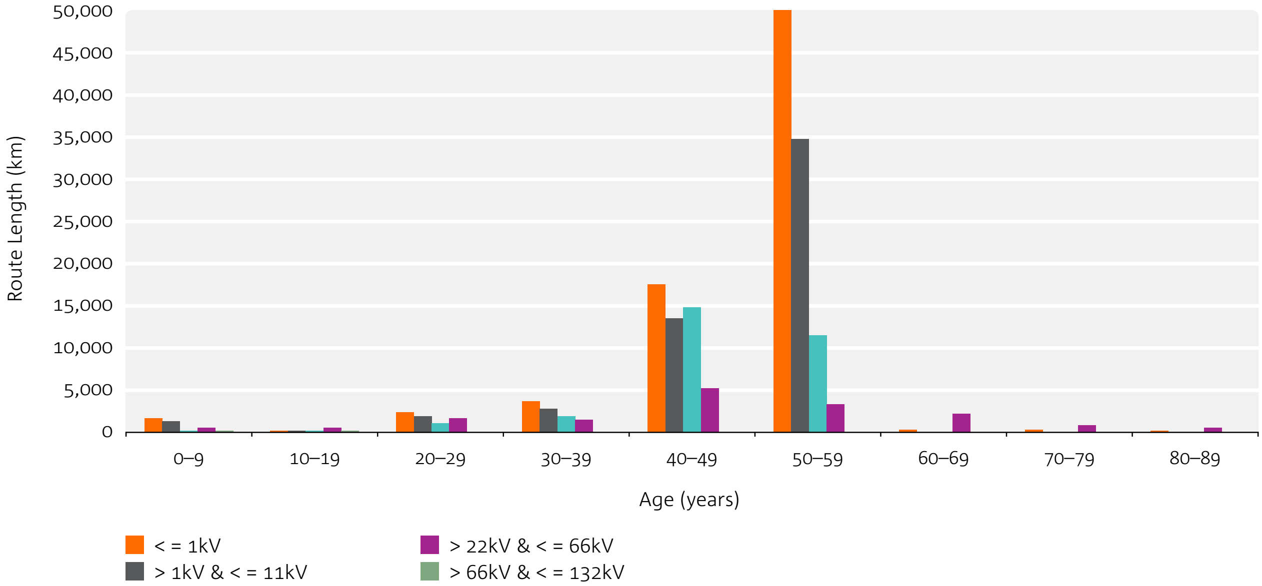
Our analysis suggests that the significant growth in replacement volumes is driven by the shape of our conductor age profile, refer to Figure 20.22. As we have discussed above, we have a large portion of conductors that were installed over a very short period, between 1955 and 1960. The calibrated lives in the model are over 80 years. Therefore, the sharp peak in the age profile is entering the leading edge of the asset life model (ie we are beginning to enter the replacement cycle for these conductors), and so replacement volumes are increasing rapidly.

We believe that the AER Repex model provides a validation of our preferred CBRM forecast. Furthermore, we believe that through the targeting of high risk conductors, we will be able to maintain performance and avoid significant further degradation.

Expenditure forecast

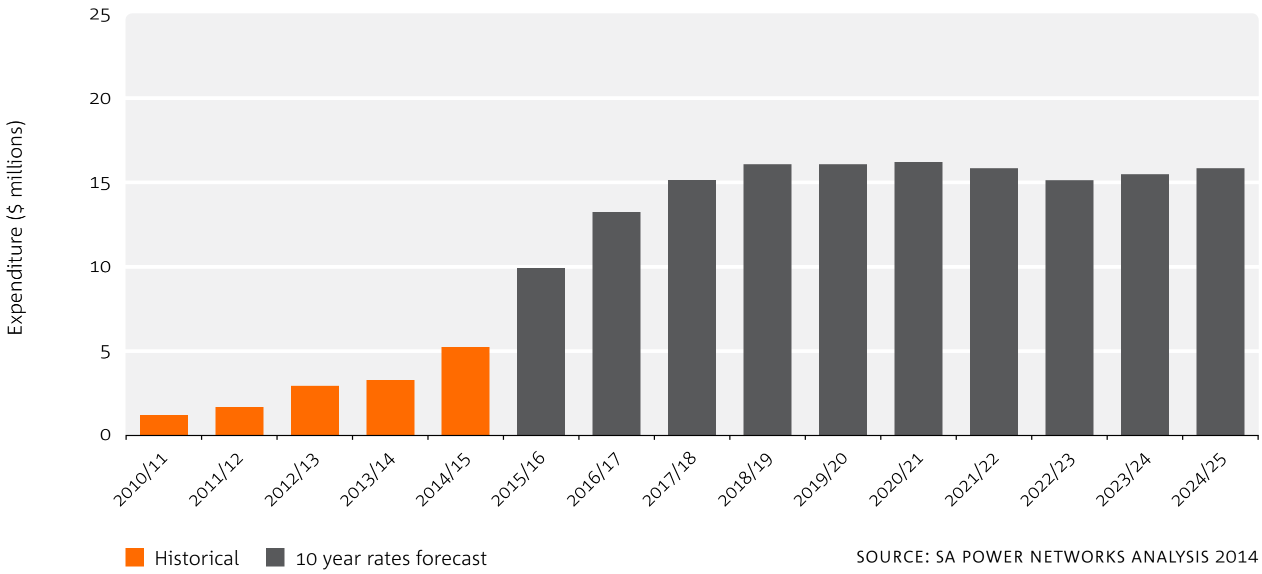
The total forecast for conductor replacement for the 2015–20 RCP is $72.2 million (2015 $). The historic and forecast conductor replacement expenditure profile is shown in Figure 20.23. For detailed analysis of our conductor replacement program refer to the Overhead Conductor AMP 3.1.10, Attachment 20.63.

Figure 20.22: Conductor age profile



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Figure 20.23: Historic and forecast conductor replacement expenditure profile (June 2015 $)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Other power line asset replacement

The forecast replacement expenditure for our priority power line assets (poles and conductors) has been outlined above. This section summarises the replacement forecast expenditure for the remainder of our power line asset classes consisting of assets such as pole top and pad mount transformers, underground cables, pole top structures, switches, service lines and regulators.

The programs listed below are the continuation of long term programs necessary for SA Power Networks to maintain an acceptable level of safety and reliability by addressing degradation of our ageing assets to meet our jurisdictional service standards and to comply with our regulatory obligations.

The total forecast for power line asset replacement 'other', for the 2015–20 RCP is $219.3 million (2015 $). Table 20.9 lists the expenditure required for each of the equipment sub-categories ranging from $1.4 million for strategic spares, to $50.8 million for overhead line components. For detailed analysis of our power line asset replacement programs, refer to the respective AMP's as listed in Table 20.9.

Table 20.9: Power line asset replacement other, forecast expenditure 2015–20 RCP (June 15, $ million)

Power line asset replacement —other	$M	AMP
Distribution transformers	47.5	3.1.01
Switchgear ground level	14.8	3.1.03
Overhead line components	50.8	3.1.06
Switchgear overhead	23.5	3.1.07
Service lines	17.7	3.1.08
Cable	26.9	3.1.09
Reclosers	31.8	3.1.13
Line regulators and capacitor banks	2.2	3.1.19
Line ancillary equipment	2.7	3.1.20
Strategic line spares	1.4	Historical
Total	**219.3**	

20.5.5 Substations

Substations consist of transformers, circuit breakers, disconnectors, supporting structures and connecting buses, protection devices and control rooms, among other items. The priority assets expenditure items in the substation category are transformers and circuit breakers. The total forecast capital expenditure for substations in the 2015–20 RCP is $114.1 million (June 2015 $).

Substation power transformers

Background

Substation power transformers provide transformation of electricity from sub transmission voltages to distribution voltage levels and are located at the bulk electricity supply substations. There are approximately 696 substation power transformers in service with typical unit replacement costs ranging from $260,000 to $1,640,000. The range of actual costs can be much wider.

Each transformer must be suitably rated to carry the load of the circuit it is placed in and be able to withstand periods of cyclic overloading to meet peak energy and emergency demands. In general, substation power transformers are moderately loaded for the majority of the time and called upon to operate at full rating or greater during peak periods of seasonal load cycles. Each transformer must also be able to withstand abnormal voltages, resulting from lightning strikes and, switching surges, as well as currents due to network faults.

As the substation power transformers age and deteriorate, they become more prone to failure. A failure of a transformer may result in unplanned supply interruptions to customers. However, as substation transformers contain insulating oil and faults can result in significant energy being released within the transformer, there is a commensurate risk of explosive failures which can result in subsequent oil fires, damage to co-located or adjacent assets, and potential environmental pollution from release of oil.

SA Power Networks undertakes prudent asset management of power transformers, through condition and performance monitoring with routine inspections and maintenance, overhaul maintenance and refurbishment to extend the asset service life and a long term replacement program, consistent with sound asset and risk management principles.

Failure modes and consequences
Substation transformers are generally reliable with historically low failure rates until they approach the end of their service life. The consequences of in-service failures include supply interruption to large numbers of customers (up to 20,000) and catastrophic failure.

Typical causes of transformer faults are:
- mechanical failure — usually due to a through fault on the distribution network;
- insulation failure — due to lightning, over-voltages during switching, internal short circuit and water ingress, insulating paper deterioration or poor oil condition; and
- thermal failure — due to high resistance connections, or overloading or cooling equipment failure.

The consequence of a transformer fault can include the following:
- external flashover and damage to HV bushings;
- oil fire;
- distortion of tank, winding, lead supports;
- short circuit between turns; and
- winding collapse.

The response time to replace a large transformer is from five to 20 days provided adequate spares are readily available. Failed transformers are replaced utilising strategic spares. A lead time of up to 12 months is the typical duration for the new power transformer to be purchased, manufactured, and delivered. Over the last five years there has been a rising trend in the number of failures.

Condition assessment
The ages of substation transformers in SA Power Networks' network range up to 72 years, averaging 35 years. Manufacturers generally design transformer insulation to an international standard that aims to achieve a nominal insulation life of approximately 20 years for continuous full load applications. This design criterion is typically well away from the normal operating conditions of a substation transformer and therefore, transformers are able to attain service lives ranging approximately 40–60 years in practice.

A comprehensive condition monitoring and maintenance regime can substantially reduce the incidence of failures through the early detection of incipient degradation and damage to transformers and therefore allow for a strategic response to developing issues.

Inspection and condition monitoring tasks are scheduled at standard intervals in accordance with our Network Maintenance Manual (Manual 12). Monitoring condition trends over time is a primary strategic asset management tool which tracks deterioration over time. As areas of concern are identified, condition monitoring frequencies are increased as the risk of an impending failure becomes apparent. For further explanation of transformer failure modes and our condition monitoring regime, refer to the Substation Transformers AMP 3.2.01, Attachment 20.64.

Forecasting approaches
We have undertaken an assessment of the level of power transformer replacement using multiple methodologies as follows:
- Independent top down forecast undertaken by Aurecon;
- CBRM model forecast developed by EA Technologies;
- Targeted — targets specific asset model or asset with a specific failure mode
- Historical trend — extrapolation of historical trends in numbers of replacements and spend; and
- AER Repex model.

An explanation of the forecasting methodologies is provided in the power line section above.

All of the forecasting methodologies derived comparable results for power transformer replacement. The results of the analysis can be found in the Substation Transformers AMP 3.2.01.

The preferred forecast methodology adopted by SA Power Networks for replacement capital expenditure for power transformers is the CBRM approach. The CBRM approach is preferred because of its granularity as specific transformers are identified for replacement.

SA Power Networks also requires a targeted program to prudently remediate power transformer models with specific problems. The targeted program is necessary to ensure these transformers reach their maximum serviceable life.

Expenditure forecast

A total of 34 substation transformers (includes small, medium and large transformers), are forecast to be replaced in the 2015–20 RCP, at a cost of $26.6 million (2015 $). The historic and forecast replacement expenditure profile is shown in Figure 20.24 below. As can be seen, our overall proposed substation transformer replacement expenditure is consistent on average with historic expenditure.

The relatively high 2010/11 capital expenditure was due primarily to the unplanned replacement of the Burnside transformer that was unable to be refurbished on site.

The highlighted targeted program is necessary to enable a portion of our young transformers to reach their specified design life. Works include replacement of rusty radiators.

Substation circuit breakers

Background

Circuit breakers are power switching devices installed within substations to selectively control the energisation of electricity distribution equipment and provide protection for the public, personnel and equipment by selectively isolating network faults.

The safe and reliable operation of our circuit breaker assets is vital to network operation, with circuit breakers playing an essential role in limiting risk exposure to the public, personnel and equipment.

Failure modes and consequences

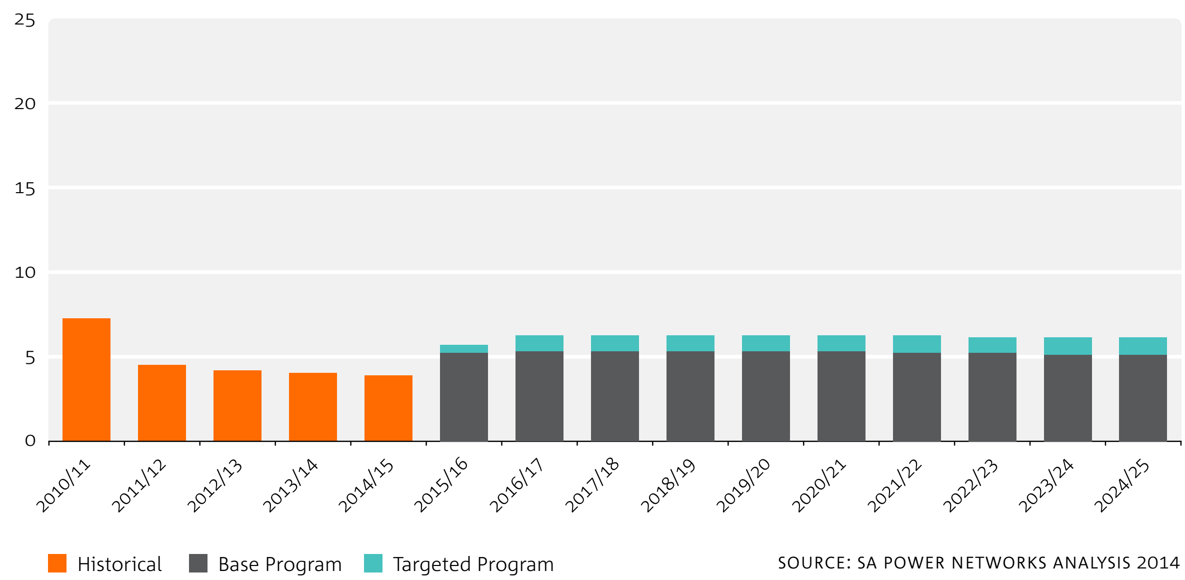
Circuit breaker failures can be classified into a number of common types based on the nature of failure and the consequential effect on circuit breaker performance. The root cause for the failure mode will usually be specific to a particular construction, but typical failures include:

- failure to trip, resulting in slow clearing of network faults, extended outages and consequential network damage (or network instability);
- failure to reclose, resulting in an extended interruption of supply for transient faults; and
- failure to interrupt, resulting in a catastrophic explosive failure resulting in public and personnel safety risk, environmental impacts and widespread network outages.

Generally, the design of the network is such that faulty circuit breakers can be bypassed by switching or with mobile plant to allow restoration of supply. This allows for individual circuit breakers to be safely isolated to enable replacement, inspection and maintenance.

In the event of circuit breaker failure, operation can typically be restored within a few hours, subject to the location, circuit breaker function and nature of the failure. However, where a simple bypass arrangements is not possible, supply interruption may exceed 12 hours. Bypassing a failed circuit breaker will put further network load at risk as the network will be operating under abnormal conditions. This means there is an increased risk of subsequent faults occurring in other parts of the network causing extensive outages.

Figure 20.24: Historic and forecast substation power transformer replacement expenditure profile (June 2015 $ million)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Condition assessment
SA Power Networks' circuit breaker assets vary greatly in age and construction, from oil insulated circuit breakers to modern vacuum and SF6 insulated units. SA Power Networks' HV circuit breaker assets operate across a range of network voltages including 66kV, 33kV, 11kV, 7.6kV and 6.6kV with service lives extending to 78 years.

As of 30 June 2014, there are approximately 1,920 circuit breakers in service on the network with unit replacement values ranging from $250,000 to in excess of $500,000.

Historical replacement expenditure is underpinned by investment in aged, deteriorated and unreliable circuit breakers in rural 33kV and 66kV distribution networks, with significant additional expenditure between 2011 and 2013 required to replace poor condition, oil insulated 11kV indoor circuit breakers.

Replacement expenditure forecasts for 2015 through 2025 reflect a change of investment focus driven by the completion of targeted programs in the 66kV and 33kV networks and the need for greater ongoing levels of investment to manage the current fleet of poor condition oil insulated 11kV indoor circuit breakers.

Forecasting approaches
We have undertaken an assessment of the level of circuit breaker replacement using multiple methodologies as follows:
- independent top down forecast undertaken by AECOM;
- CBRM model forecast developed by EA Technologies;
- Targeted — targets specific asset model or asset with a specific failure mode;
- historical trend — extrapolation of historical trends in numbers of replacements and spend; and
- AER Repex model.

An explanation of the forecasting methodologies is provided in the power line section above.

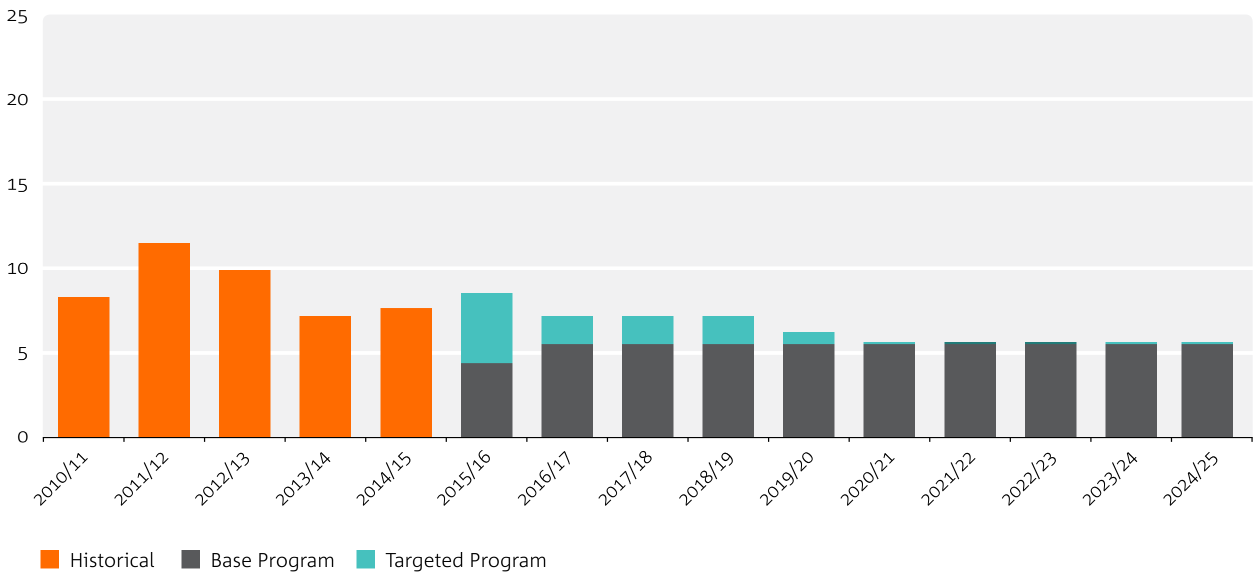
All of the forecasting methodologies derived comparable results for substation circuit breaker replacement. The results of the analysis can be found in the Substation Circuit Breaker AMP 3.2.05, Attachment 20.65.

The preferred forecast method adopted by SA Power Networks for the replacement capital expenditure for circuit breakers is the CBRM approach. The CBRM approach is preferred because of its granularity as specific circuit breakers are identified for replacement.

SA Power Networks also requires a targeted program to prudently remediate substation circuit breaker models with specific problems. The targeted program is necessary to ensure these circuit breakers reach their maximum serviceable life.

Expenditure forecast
A total of 60 substation circuit breakers (includes 11kV switchboards and capacitor bank switches), are forecast to be replaced in the 2015–20 RCP, at a forecast cost of $35.8 million (June 2015 $). The historic and forecast replacement expenditure profile is shown in Figure 20.25 below. For detailed analysis of our substation circuit breaker program, refer to our Substation Circuit Breaker AMP 3.2.05.

Figure 20.25: Historic and forecast substation circuit breaker replacement expenditure profile (June 2015, $ million)



The circuit breaker capital expenditure was abnormally high in 2011/12 and 2012/13 due to the unplanned replacement of a number of 11kV switchboards that failed to perform as designed, resulting in premature failure. This particular type of 11kV circuit breaker has now been removed from the network, as such we forecast circuit breaker capital expenditure to return to historical levels.

Other substation assets

The forecast replacement expenditure for our priority substation assets (transformers and circuit breakers) has been discussed above. This section summarises the replacement forecast expenditure for the remainder of our substation asset classes consisting of assets such as auxiliary supplies, substation civil infrastructure, protection relays, SCADA devices and other items.

The programs listed below are the continuation of long term programs necessary for SA Power Networks to maintain an acceptable level of safety and reliability by addressing degradation of our ageing assets to meet our jurisdictional service standards and to comply with our regulatory obligations.

The total forecast for substation asset replacement (excluding transformers and circuit breakers), for the 2015–20 RCP is $51.7 million (June 2015 $). For detailed analysis of our substation replacement programs, refer to the respective AMP's as listed in Table 20.10

Table 20.10: Substation asset replacement (excludes transformers and circuit breakers), forecast expenditure 2015–20 RCP (June 2015, $ million)

Substation asset replacement	$M	AMP
Surge arrestors	1.5	3.2.03
SCADA devices	9.3	3.2.04
Capacitor banks	0.7	3.2.07
Auxiliary DC supplies	1.5	3.2.08
Mobile substations	0.4	3.2.13
Protection audits and relays	22.6	3.2.14
Substation civil infrastructure	3.0	3.2.16
AC panels	1.2	3.2.22
Substation insurance spares	5.9	Historical
Unplanned major refurbishment	5.1	Historical
Standby power stations	0.5	Historical
Total	**51.7**	

20.5.6 Telecommunications

This section summarises the replacement forecast expenditure for our telecommunications assets which consists of assets such as 48V DC systems, data network, microwave radio, optical fibre network and pilot cable network. This forecast excludes expenditure associated with our Telecommunications Network Operations Centre (**TNOC**) as this expenditure is included in the Non-Network subcategory, refer to Section 20.8.2.

The programs listed below are the continuation of long term programs necessary for SA Power Networks to maintain an acceptable level of safety and reliability by addressing degradation of our ageing assets to meet our jurisdictional service standards and to comply with our regulatory obligations.

The total forecast for telecommunications replacement, for the 2015–20 RCP is $38.5 million (June 2015 $), excluding non-network related telecommunications expenditure. For detailed analysis of our telecommunications asset replacement programs, refer to the respective AMPs as listed in Table 20.11.

Table 20.11: Telecommunications asset replacement, forecast expenditure 2015–20 RCP (June 2015, $ million)

Telecommunications replacement	$M	AMP
Data network	3.9	3.3.12
Microwave radio	3.0	3.3.01
48 volt DC systems	1.6	3.3.02
Pilot cable network	15.4	3.3.03
Optical fibre network	2.7	3.3.04
Miscellaneous radio systems	7.7	3.3.05
UPAX telephone network (network component)	0.3	3.3.07
SDH network	0.5	3.3.10
Minor works unplanned	3.3	Historical
Total	**38.5**	

Pilot cables are a critical part of SA Power Networks distribution infrastructure. They provide telecommunication facilities between SA Power Networks substations, telecommunication and network control centres. SA Power Networks has a priority telecommunications replacement program to replace the obsolete metropolitan and CBD 33kV CBD pilot cable systems.

The metropolitan pilot cable program is a continuing program to migrate the aerial pilot cable system over to the fibre optic network. We are experiencing significant problems with the catenaries separating from the pilot cable, resulting in significant sagging of the pilot cables and environmental impacts such as UV and vegetation, is resulting in failure of these pilot cables. Given the construction of the pilot cable, there is no permanent remediation solution. The metropolitan pilot replacement program commenced in the current RCP and is expected to be completed by 2025. The cost of the 2015–20 program is $7.4 million (June 2015 $).

The majority of our CBD pilot cables were included in the design and construction of major CBD distribution assets. They were installed and commissioned at the same time as major power assets such as high voltage lines and substations and operate under the same environmental conditions.

The CBD pilot cable system is over 50 years old and is now beyond its serviceable life. In total there are 64 copper pilot circuits in the CBD with 20 installed pre 1958, 20 installed from 1968 to 1978 and the remaining 24 installed after 1978.

The CBD pilot cables are in extremely poor condition, a large portion of the cables are lead/paper sheath, which have a tendency overtime to develop pin holes where water enterers and breaks down the paper sheath creating short circuits, as such we have experienced high volumes of electrical faults, including intermittent tripping of our underground power line network, on average of three trips per annum.

We are proposing to migrate the high risk CBD pilot network to optical fibre in the 2015–20 RCP, at a cost of $8.0 million (June 2015 $), which is included in the pilot cable network forecast.

20.5.7 Safety (general)

This section should be read in conjunction with Chapter 11 ‘Safety for the community’, and the referenced attachments.

Safety expenditure is specifically required to comply with applicable regulatory obligations or requirements associated with safety and the provision of SCS and to ensure prudent and efficient management of safety risks in order to maintain the safety of the distribution system through the supply of SCS, the second and fourth objectives in clause 6.5.7(a) of the NER. This expenditure is for replacement of ‘like for like’ assets, whereas augmentation related safety expenditure requires the installation of new assets or the replacement of existing assets with improved technology. Safety augmentation expenditure has been included in the augmentation capital forecast discussed in Section 20.6.5.

The safety forecast expenditure in the current RCP is $55.9 ($ million, nominal), $44.4 million below the AER allowance of $100.3 ($ million, nominal), refer to Table 20.12.

The variance in safety expenditure in the current RCP has arisen because we were unable to safely gain access to our manholes and ducts while energised, to undertake remediation. Therefore this work had to be undertaken during the evening to limit disruption to customers, significantly slowing the remediation program.

Additionally, some safety expenditure relating to our CBD LV switchboards and 33kV switching cubicles, was delayed due to the complexities in implementing the proposed solutions and the availability of scarce specialist resources. This in turn required us to revise our remediation strategy and re-categorise projects into complex ‘like for like’ solutions for substations supplying high customer load density, and simple 11kV solutions for substations supplying low customer load density. The simple 11kV solutions are able to be constructed by power line personnel who are more readily available.

We do not foresee these factors impacting on our ability to undertake the proposed 2015–20 RCP as forecast, because in most cases simpler remediation solutions have been developed, and a permanent afternoon shift has been established in the CBD, alleviating resource constraints.

SA Power Networks’ Safety replacement forecast expenditure for the 2015–20 RCP is summarised in Table 20.13.

Table 20.12: Comparison of Safety AER allowance and actual/forecast capital expenditure ($ million, nominal)

Safety expenditure	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Allowance	11.4	18.7	22.4	23.7	24.2	**100.3**
Actual/forecast	4.4	13.7	8.4	10.7	18.7	**55.9**

Table 20.13: SA Power Networks' safety capital expenditure for 2015–20 (June 2015, $ million)

Safety expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Forecast	15.1	18.1	18.2	17.4	16.6	**85.5**

In the 2015–20 RCP safety expenditure is focussed on activities that will maintain the appropriate safety of our network for our workforce and the general public (ie the second and fourth objectives in clause 6.5.7(a) of the NER).

The safety replacement program is a combination of new projects and a continuation of the existing programs. Refer to Table 20.14 for details of our proposed safety program for the 2015–20 RCP.

Whilst the majority of the programs listed above are a continuation from the current RCP, the CBD ducts and manholes program is a specific program as outlined below, to ensure ongoing safety for the community and our people operating the network.

The CBD is supplied via an underground power network consisting of manholes, ducts, cables and joints. There are approximately 5,500 high risk high voltage cable joints that were installed from 1961 to 1995. These cable joints are failing with an increasing trend. Many of these high risk joints are located in areas with high pedestrian traffic, presenting an increasing safety risk to the public due to the potential for manhole covers to become dislodged when joints fail catastrophically. We have developed a long term strategy to remediate these unsafe cable joints, initially targeting the highest risk joints in accordance with our CBD AMP 2.1.07.

For detailed analysis of these safety replacement programs, refer to the respective AMPs as listed in Table 20.14.

Table 20.14: Safety replacement other, forecast expenditure 2015–20 RCP (June 2015, $ million)

Safety replacement	$M	AMP
CBD ducts and manholes	22.8	2.1.07
CBD LV switchboards and 33kV switching cubicles	14.1	2.1.07
Krone switchgear replacement	10.7	3.1.03
Distribution earthing	3.7	3.1.18
Instrument transformers (CT and VTs)	2.4	3.2.02
Overhead substation switches	12.2	3.2.17
Emergency switching communication	2.2	3.3.06
Telecommunications structures	3.1	3.3.13
Elizabeth transformer stations	1.7	5.1.02
Line clearance rectification	12.6	5.1.06
Total	**85.5**	

20.5.8
Our benchmarking results support the need for increased replacement expenditure

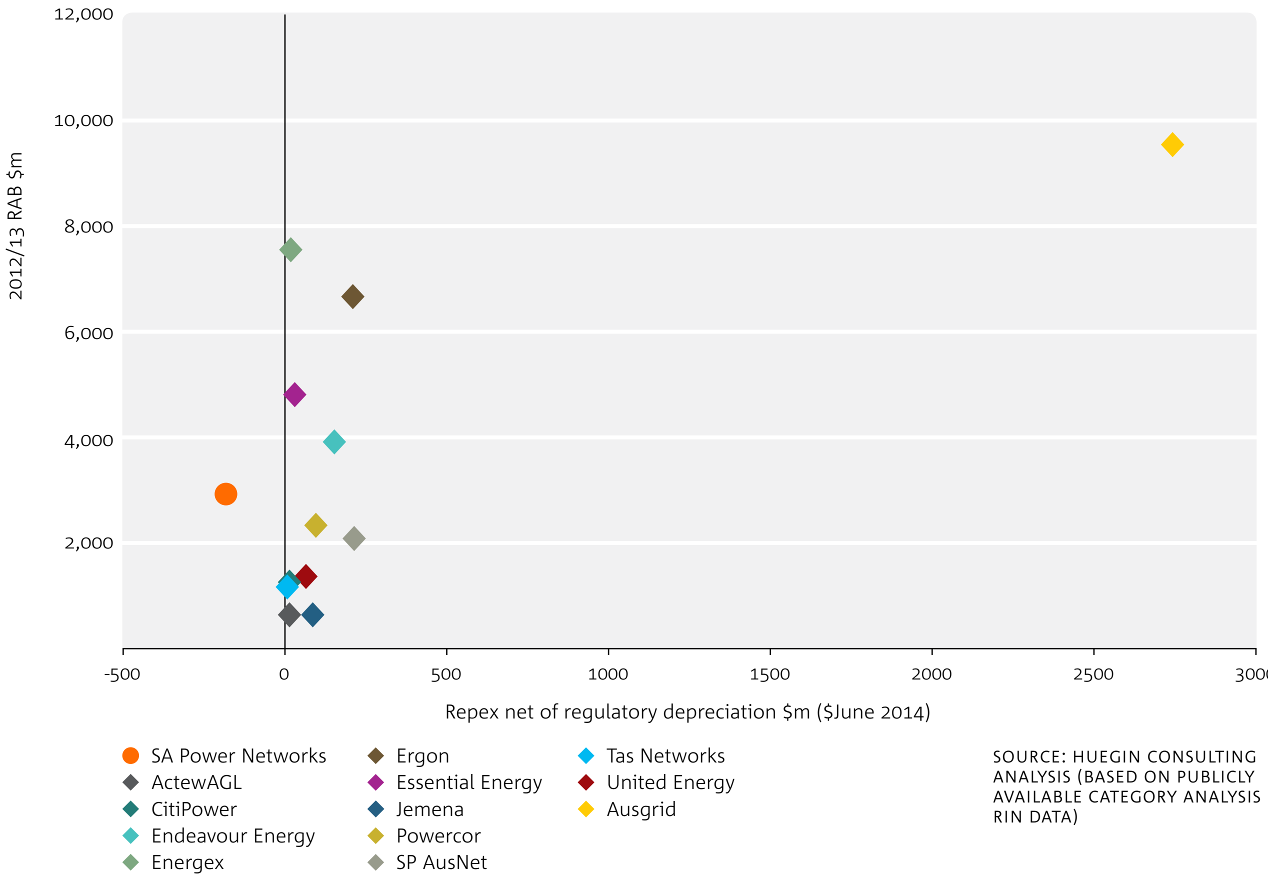
In its 2010–15 regulatory proposal, SA Power Networks was unable to justify to the AER the need to increase replacement expenditure. In the current RCP we have seen the introduction of benchmarking across DNSPs, which clearly demonstrates that SA Power Networks' expenditure on asset replacement lags that of its peers. Whilst this is only one facet of demonstrating the need to increase replacement expenditure, it provides support to the increased program presented in this Proposal.

Based on analysis of data provided in the recent Category Analysis RIN for the five years to 2012/13, Figure 20.26 compares RAB to net Repex (calculated as total replacement expenditure less accumulated depreciation for the period).

This analysis reveals that SA Power Networks' replacement expenditure has been almost $180m less than its depreciation over the five years, with replacement expenditure amounting to only 62% of depreciation. Significantly, the graph demonstrates that despite SA Power Networks spending more than the AER-approved allowance we are the only DNSP spending significantly less than depreciation.

Clearly such a low amount of replacement expenditure is not sustainable in the long term. An increase in replacement expenditure is clearly prudent to ensure assets are replaced when they reach the end of their service life and before they fail, consistent with the capital expenditure objectives.[60]

Figure 20.26: RAB v Repex net of depreciation 2008/09 to 2012/13 (June 2014 $)



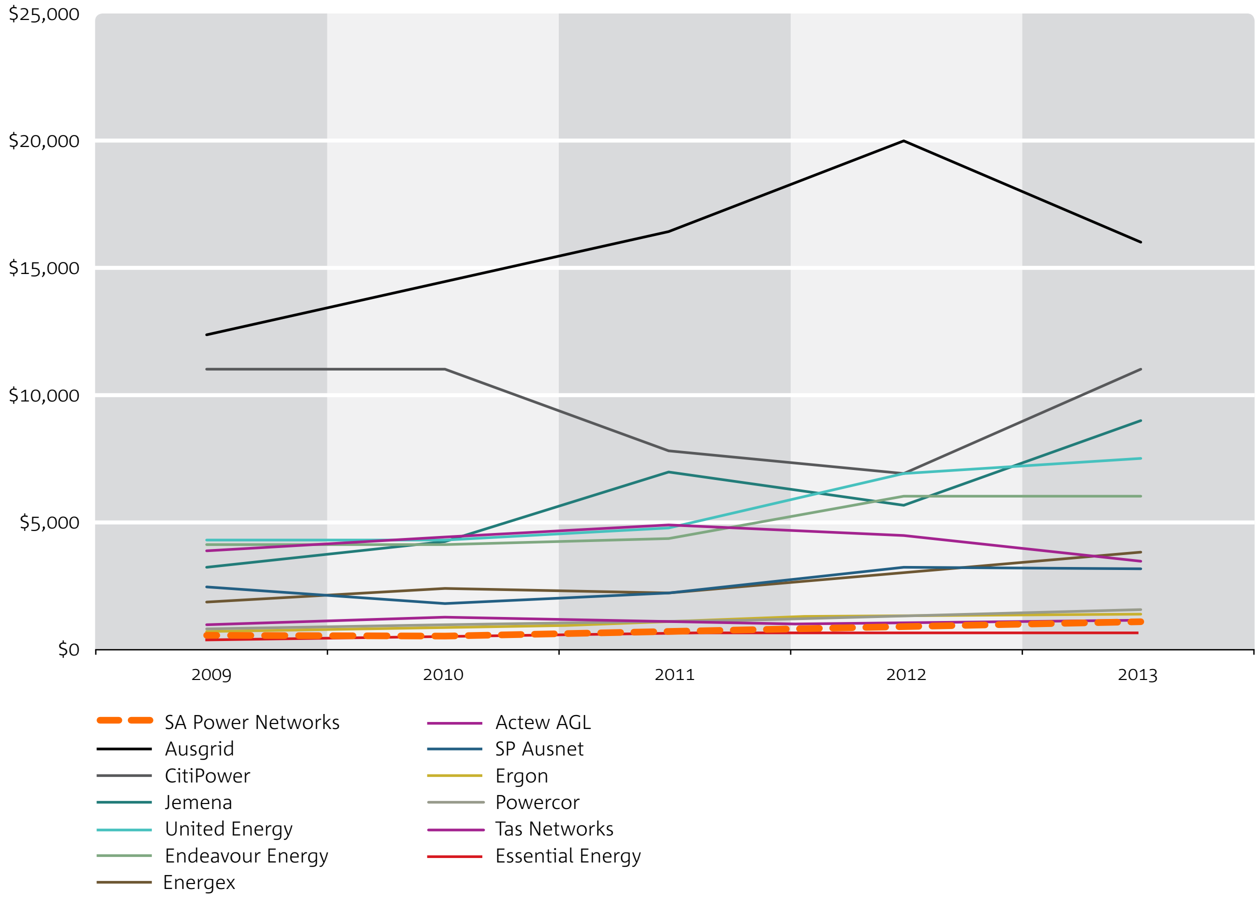
SOURCE: HUEGIN CONSULTING (BASED ON PUBLICLY AVAILABLE CATEGORY ANALYSIS RIN DATA)

60 NER 6.5.7 (a) — capital expenditure objectives

Further analysis of the Category Analysis RIN data demonstrates that SA Power Networks benchmarks amongst the lowest for replacement expenditure compared to its peers. Figure 20.27 compares replacement expenditure to line length. Due to our geographic footprint and extreme weather conditions, SA Power Networks considers that this comparison is the most informative and demonstrates that SA Power Networks is at the very low end of replacement expenditure per kilometre of line.

This analysis of the Category Analysis RIN data highlights that SA Power Networks' expenditure on replacement of assets has been prudent over the past five years. SA Power Networks' ageing portfolio of assets (refer Section 9.2.1) shows however that the current level of replacement expenditure is not sufficient to meet the capital expenditure objectives[61].

Figure 20.27: Total replacement expenditure per km route line length 2008/09 to 2012/13



SOURCE: HUEGIN CONSULTING (BASED ON PUBLICLY AVAILABLE CATEGORY ANALYSIS RIN DATA)

61 NER 6.5.7 (a)

20.5.9
Our replacement forecast outcomes reasonably reflect the AER's requirements

Chapter 6 of the NER defines what should be allowed for in the capital forecast in the building block proposal. This is prescribed through the NER capital expenditure objectives and criteria as explained in Section 20.1.

We believe that the AER should accept our capital expenditure forecasts for asset replacement (as part of the total forecast capital expenditure in our building block proposal) for the following reasons:

- we believe that the forecast activity volumes are a reasonable estimate of the volume required to both:
  - comply with our regulatory obligations and requirements associated with the provision of SCS (including, in particular, our regulatory obligation to comply with the ESCoSA-approved SRMTMP and take reasonable steps to ensure that the distribution system is safe and safely operated); and
  - maintain the safety of the distribution system;
- we have used reasonable approaches to forecast the volume of activity to achieve these objectives. The CBRM model has been widely accepted as suitable for regulatory purposes. All other models used rely upon our detailed asset data and have been calibrated to reflect our circumstances;
- the forecast volumes and expenditure are broadly supported by other assessment techniques the AER could apply:
  - analysis of RIN data indicates that we have one of the oldest networks and have been replacing assets at one of the lowest levels, consistent with the proposition that replacement volumes need to increase; and
  - we have also used the AER's Repex model to review the reasonableness of our capital expenditures forecast;
- it is prudent to manage identified defects in the manner we have proposed. Our forecast allows for the critical (ie high risk) defects to be addressed strictly within the documented remediation timeframes. However, our forecast is predicated on balancing cost impacts with lower risk defects and adopting a risk based approach that supports a 10 year strategy to remediate those defects;
- we have allowed for the prudent and efficient solutions to address the forecast needs. As noted above, we have allowed for the much lower cost life extension options in our forecast, when the options are available to us, eg pole plating instead of pole replacement. We have used recent history to estimate the proportion of poles where the use of this lower cost solution should be possible;
- we have allowed for the efficient unit cost for the assumed solutions. Our unit cost methodology has been validated by GHD, refer to Attachment 20.19. Our unit costs are based upon our historical costs. A significant proportion of these costs are a result of open competitive tender practices; and
- where we have a step increase in volumes, we have profiled the forecast to reflect a prudent and efficient delivery timeframe.

Taken together, these points provide a compelling case that our replacement expenditure forecast satisfies the capital expenditure criteria.

20.6

Augmentation expenditure

This section explains why our forecast capital expenditure for augmentation is required in order to achieve the capital expenditure objectives and how that forecast expenditure reasonably reflects the capital expenditure criteria and takes into account relevant capital expenditure factors. This section should be read in conjunction with Chapters 9 through to 15 and the referenced attachments to gain a full appreciation of our proposal.

Augmentation capital expenditure relates to expenditure required to expand or upgrade network assets to address changes in demand for standard control services or to maintain quality, reliability and security of supply in accordance with regulatory requirements. This section does not include connections and other customer related works. For details on connections capital expenditure refer to Section 20.7.

Augmentation expenditure comprises the following key components:

- **Demand driven augmentation:** Works required to meet forecast demand that necessitates the extension or upgrade of our sub-transmission, distribution and low voltage networks;
- **Reliability:** Installation of assets required to maintain the reliability of the network to ensure compliance with ESCoSA's defined reliability service standards;
- **Strategic:** Specific one-off programs to manage key network risks and compliance issues and/or optimise long term expenditure;
- **Environmental:** Works necessary to address environmental risks within the network to comply with Environmental Protection Authority (**EPA**) requirements;
- **Safety:** Expenditure necessary to maintain the safety of our network (excluding replacement works) for SA Power Networks' workforce and the general public and include a number of initiatives arising from our Customer Engagement Program; and
- **Other expenditure:** Primarily our Power Line Environmental Committee (**PLEC**) undergrounding.

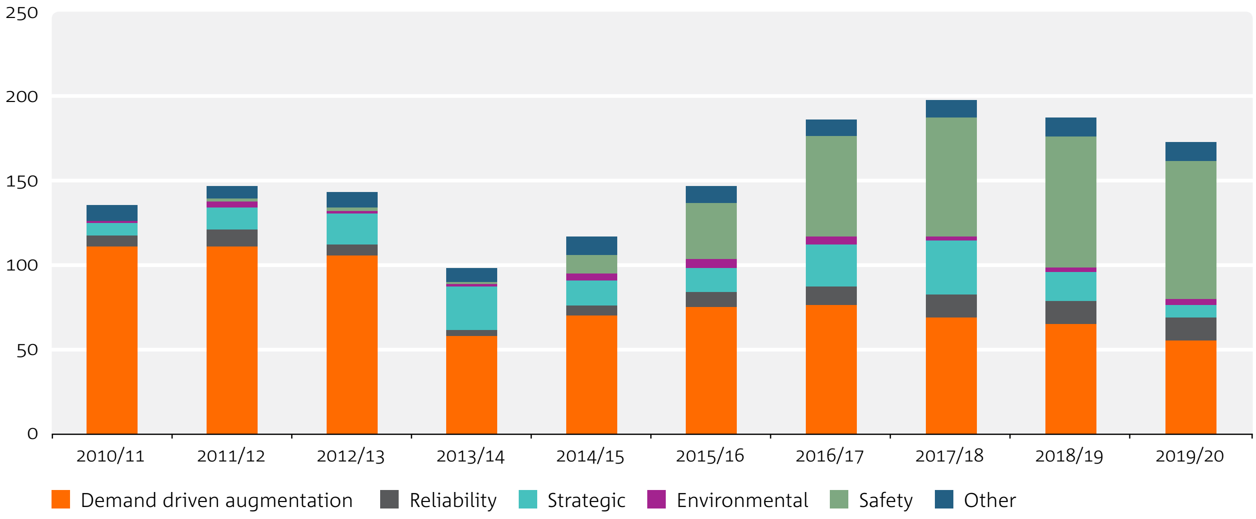
Figure 20.28 shows SA Power Networks total augmentation capital expenditure for the 2010–15 RCP, along with the total augmentation forecast capital expenditure that we consider will be required during the 2015–20 RCP in order for us to achieve the capital expenditure objectives described in Section 20.1 of this chapter.

For demand driven augmentation we discuss key areas of expenditure according to their drivers and make reference to the material projects for the 2015–20 RCP.

For the remaining components of augmentation expenditure (ie reliability, strategic, environmental, safety and other), we provide detailed discussion of the key capital expenditure categories according to our assessment of materiality of expenditure levels or risk.

For other sub-programs, we provide brief summary information, with more detailed discussion for these programs being consigned to the relevant AMP as identified in the sub-program discussion.

Figure 20.28: Augmentation expenditure by key components (June 2015, $ million)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

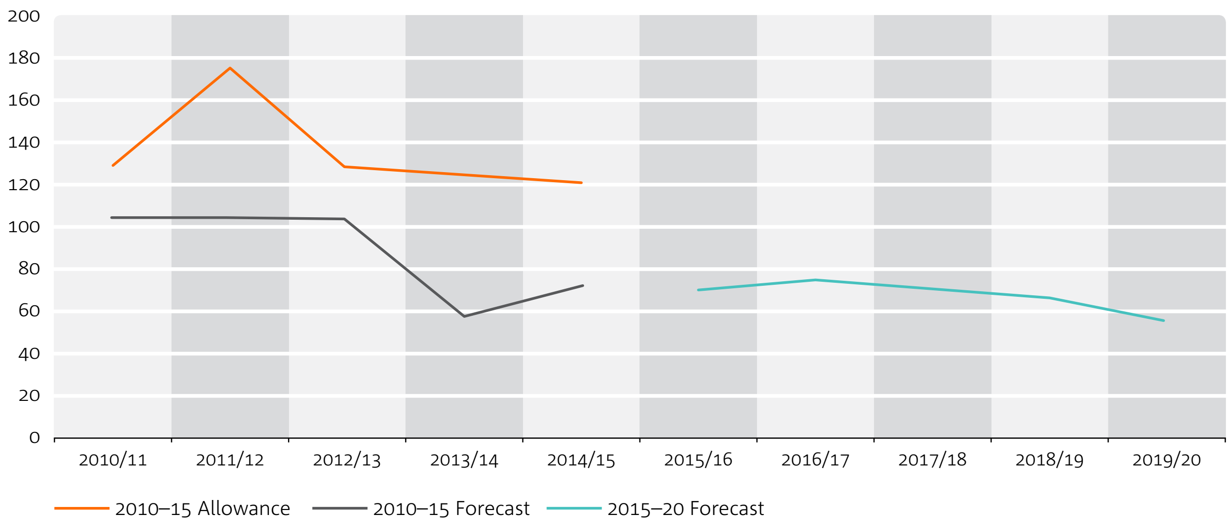
20.6.1 Demand driven expenditure

This section should be read in conjunction with Chapter 12 'Growing the network in line with South Australia's needs' and 13 'Ensuring power supply meets voltage and quality standards', along with the referenced attachments.

The demand driven program consists of works required to meet or manage the expected demand for SCS over the 2015–20 RCP (NER 6.5.7 (a)(1)).

Figure 20.29 below details our forecast expenditure for the current RCP compared to the allowance for the current RCP and our forecast expenditure for the 2015–20 RCP.

Figure 20.29: Demand driven augmentation — historic and forecast expenditure profile (June 2015, million $)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Current period outcomes
The demand driven augmentation forecast expenditure for the current RCP is $436 million (nominal), 36% below the AER allowance of $677 million (nominal)(refer Table 20.15).

At the time of our 2010–15 RCP regulatory proposal, global demand growth for South Australia was forecast at 2.4%. Actual global demand has been basically flat over the current RCP (refer to Figure 20.30), although local spatial demand did vary with reductions in some locations and increases in others.

The lower than forecast growth in global demand was due to external factors beyond our control, including a general economic downturn that resulted in the closure of some commercial and industrial businesses (especially manufacturing), and a slow down in the new housing industry and agricultural industry. In addition, a significant uptake of solar PV resulted in the connection of over 580MW of embedded PV generation in the distribution network over the RCP, which exceeded the forecast global (State) demand growth.

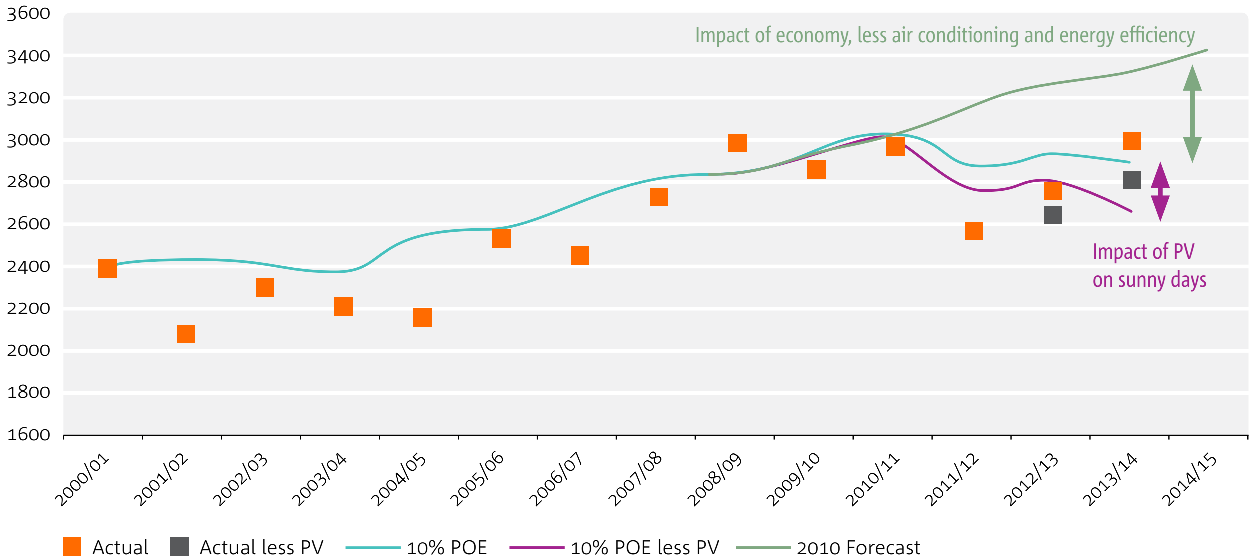
The impact of the solar embedded generation was most profound at the State level and in parts of our network that historically peaked in the afternoon. Many such regions now peak after 7:00pm rather than the traditional 1:00pm to 5:00pm period. The estimated future growth of solar PV has been included in the 2015–20 RCP forecasts, but its impact in reducing peak demand will be much lower for many regions as PV output is very low after 7:00pm. Measured growth in the 8pm demand from 2009/10 to 2013/14 still occured in several regions because once PV ceased to have an impact demand was continuing to grow.

In some regions such as the Adelaide CBD we have also detected an improvement in customer energy efficiency from building design practices (eg green star ratings) which has added to the global demand growth curtailment. As a consequence of the measured slow down generally in demand growth, the demand driven augmentation program in the current RCP was prudently deferred from 2012 onward.

Table 20.15: Comparison of demand driven augmentation AER allowance and actual/forecast capital expenditure ($ million, nominal)

Demand Driven Expenditure	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Allowance	128.8	173.7	127.8	125.0	121.4	**676.7**
Actual/forecast	102.3	103.2	102.1	57.0	71.5	**436.0**

Figure 20.30: Global 10% probability of exceedance (**PoE**) demands (MW) at 1630 EST (5pm local time) excluding major business



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Major projects must pass the rigorous planning criteria test before they are committed, and consequently several have been deferred to the next period or later due to the lower than expected demand growth. For example, projects designed to manage network contingencies are not considered until the measured demand (temperature adjusted) exceeds the network contingency capacity. For the Transmission network this is with a 10% PoE temperature adjustment and for the zone substation network a 50% PoE temperature adjustment. All major projects are also subject to a Regulatory Test (ESCoSA specified prior to 2014 and the AER's RIT-D after 2014).

Within the current RCP, SA Power Networks had included 33 major projects each with forecast expenditure in excess of $5 million. The total estimated cost of these 33 projects was $385.5 million ($ 2008).

Of these 33 major projects, SA Power Networks has or expects to complete 20 by the end of the 2010–15 RCP, with a further three in progress. Of the remaining projects, most of these have not been undertaken due to a reduction in load growth changing the timing of the constraint the project was proposed to resolve, for example, the implementation of Post Office Place and Seaton 66/11kV substations planned for 2014, has been deferred to beyond 2020.

For most of the major projects, which have been deferred, constraints are now forecast to occur after 2020. However, for a few of the planned projects, measured peak demand over the summer of 2013/14 has exceeded the planning criteria requiring the projects to proceed on the cusp of the current and next RCP eg the construction of a 66kV transmission line in the Morphett Vale East to Willunga network is required to resolve its constraint. A small number of the projects forecast to be undertaken during the 2010–15 RCP, are now forecast to occur in the 2015–20 RCP.

Non-network solutions were also considered as required by the NER and the EDC. Non-network projects were adopted where this was more cost effective for customers. For example, a $5.4 million (June 2015 $) non network solution was implemented at Bordertown. This project comprised the construction of a third party owned, 4MW power station which has been connected to Bordertown zone substation via an express 11kV distribution line. This allowed the deferral of the proposed second sub-transmission line between Keith to Wirrega, a capacity upgrade at Bordertown zone substation, and upgrade of the Keith Transmission Connection Point to beyond 2020. Such non network solutions have also been actively considered for the 2015–20 RCP constraints including a potentially viable alternative for the Morphett Vale East to Willunga network project.

All Electricity Transmission Code (**ETC**) compliance driven projects proposed for the 2010–15 RCP such as City West 275/66kV supply to Adelaide CBD, Mount Barker South 275/66kV, Wudinna 132/66kV, Kadina East 132/33kV, Whyalla Central 132/33kV, Hummocks 132/33kV, Waterloo 132/33kV and Ardrossan West 132/33kV transmission connection point substations have been completed. These projects were completed in conjunction with ElectraNet and were primarily driven by the change in the ETC in 2008.

For a detailed summary of the major projects in the 2010 Determination and an indication of those completed, in progress or deferred, refer to our Distribution System Planning Report (**DSPR**) AMP 1.1.01, Attachment 7.4.

In summary, the variation in expenditure compared to allowance was due to uncontrollable external factors such as economic downturn and the rapid take up of embedded PV generation resulting in deferral of projects.

In the current RCP, SA Power Networks can demonstrate our augmentation program was prudent as we undertook the most appropriate course of action at the time, and our expenditure was efficient. We only implemented programs that resulted in the lowest long term costs to the consumer. For example, projects were only undertaken when the constraint necessitated action (constraints were adjusted annually based on the latest spatial demand forecasts).

The changes in customer demand have been factored into the 2015–20 RCP demand forecast, including allowances for the increase in embedded PV generation. An independent forecast on the take up of PV generation was produced by Energeia[62] on behalf of SA Power Networks. Future growth in PV generally has a low impact on the demand forecast after 2015 as the time of network peak is now during hot evenings when PV output is very low (after 7:00pm). However, there are a few locations which still peak before 6:00pm such as the Western Suburbs of Adelaide where PV can still have an impact. Global changes in economic factors such as state population and GDP growth and improved energy efficiency initiatives have also been included by reconciliation with AEMO's July 2014 SA Generation forecast trend. The growth trend for the non major customer portion of AEMO's forecast is basically flat for the 2015–20 RCP.

For further detail on demand driven augmentation current period performance, refer to the DSPR AMP 1.1.01.

62 Assessment of tariff options in South Australia, Energeia, July 2014

Forecasting methodology
SA Power Networks' sub-transmission and distribution network augmentation is generated either from requirements to upgrade our infrastructure resulting from changes to the ETC, or as an output of our planning process to ensure compliance with NER 6.5.7(a) objectives 1 and 2. The network planning process considers when network and/or specific customer load growth breaches the Network Planning Criteria. This triggers a network constraint that must be addressed by either a network or non-network solution. The process followed in planning and augmenting the distribution network is shown in Figure 20.31.

Key inputs that underpin our demand driven augmentation capital expenditure forecasts include:

- Network Planning Criteria: defining the level of redundancy required (at SA Power Networks' connection points, zone substations and transmission lines) to meet EDC and ETC standards, reliability standards and standards related to the maintenance of security of supply; and
- Spatial peak demand growth.

Network planning criteria
SA Power Networks' Network Planning Criteria are a key driver of future demand related capital expenditure because they define when a network 'constraint' exists that must be addressed by means of a prudent network or non-network solution. Constraints occur when forecast load demand exceeds the capacity of a particular distribution system. The Planning Criteria also define the level of redundancy required in particular parts of the distribution network.

SA Power Networks' planning criteria incorporates the objectives of establishing and maintaining compliance with all regulatory obligations including, National and International Standards, Codes of Practice, the Electricity Act, and satisfying the obligations specified within the EDC and the NER. In particular, the criteria embody obligations imposed by legislation including the requirement to adhere to standards and practices generally accepted as appropriate either internationally or throughout Australia by the electricity supply industry and to ensure the security and reliability of electricity supply to customers.

The criteria must ensure that the requirements relating to power quality, short circuit capability, system stability clearing times, reliability and system security contained in Schedule 5.1 of the NER are met. We are also obliged to comply with the mandatory ETC requirements.

The forecast load for future years contained within the 10% and 50% Probability of Exceedance (**PoE**) load forecasts is compared with the capacity rating of the relevant network segments to produce a list of overloaded or constrained assets. This is undertaken for both system normal (**N**) and single contingency conditions (**N-1**).

SA Power Networks plans to implement solutions for those assets forecast to be overloaded under normal conditions, prior to the overload occurring. However, SA Power Networks also plans to implement solutions to ensure those assets are not overloaded under contingency conditions after a potential overload is measured. The criticality of the asset is taken into account by the PoE used (10% or 50%) and the allowed maximum load at risk (load that cannot be supplied), eg Transmission Connection Points and CBD zone substations use 10% PoE and other zone substations use 50% PoE. For more details refer to the DSPR AMP 1.1.01.

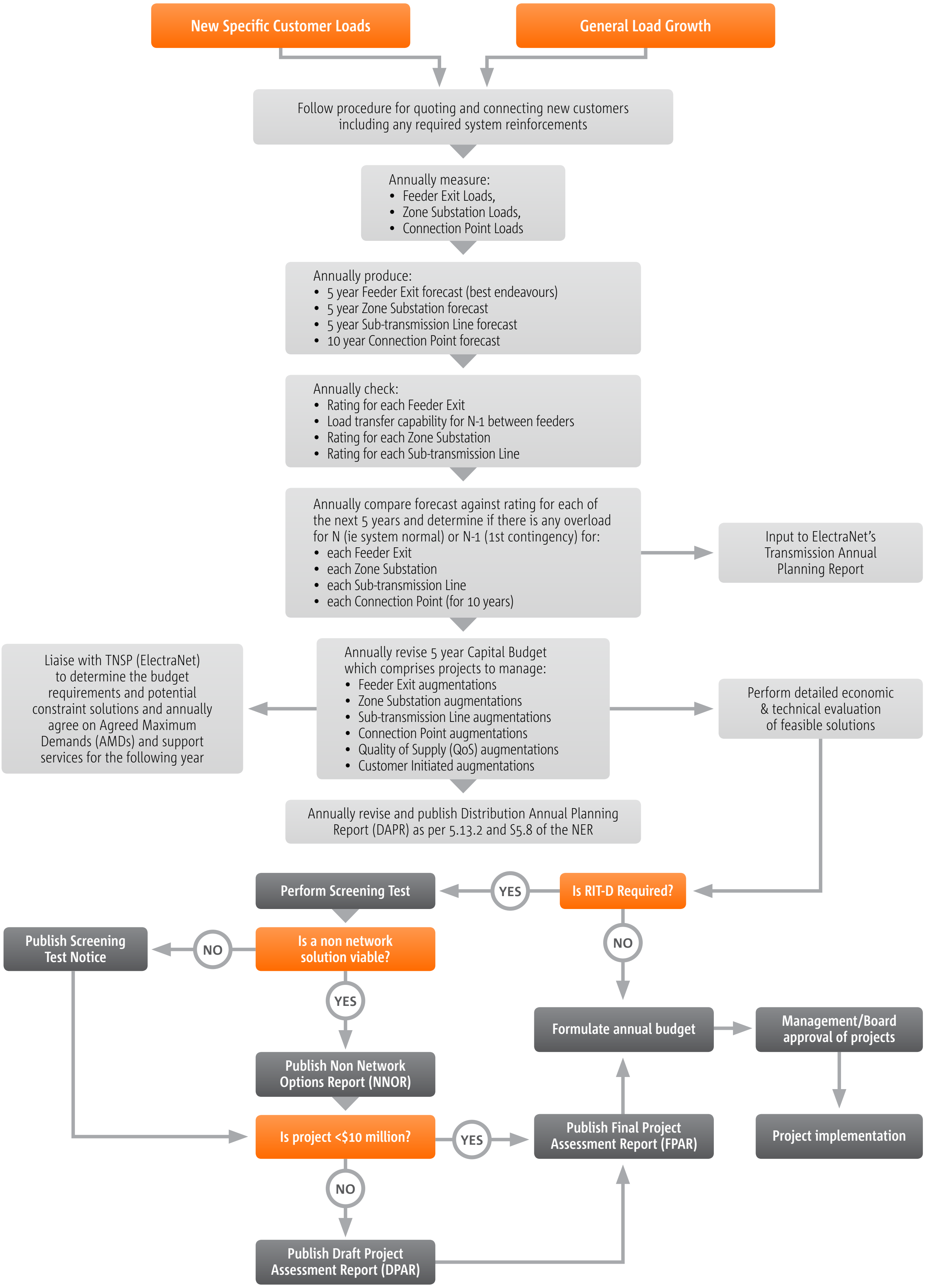
The Network Planning criteria are also published in the Distribution Annual Planning Report (**DAPR**) on our web site each November. A copy of our current DAPR is contained in Attachment 7.3.

Spatial peak demand forecasting
Traditionally SA Power Networks applied a 'peak to peak' demand forecasting methodology. During the AER review of ElectraNets' regulatory proposal for the 2013–2018 RCP, the AER was of the view that SA Power Networks should consider adopting a forecasting approach aligned to that of AEMO as this would enable an easy reconciliation of the demand levels on the ElectraNet Transmission System. In response, we have since (2013) adopted a 10% and 50% PoE forecasting methodology, consistent with most other DNSP's. In addition, we engaged Acil Allen to develop an independent and transparent spatial forecasting tool in 2013 for our use. This tool has been tested against the measured 2014 summer loads and allows reconciliation with a State-wide Forecast. For this RCP we have chosen to use the AEMO July 2014 SA forecast for this purpose.

The Acil Allen forecasting tool performs regression analysis to weather correct recorded load readings with respect to historic temperatures dating back to 1978. In order to account for econometric factors, the temperature corrected PoE spatial forecasts are able to be reconciled to the next level of the network (ie zone substations reconciled to connection point, connection points reconciled to total State). The tool considers the impact of past and future embedded generation (including PV), spot loads, load transfers and the behaviour of major customers in arriving at its final forecast values for the nominated PoE level.

When reconciling the aggregated Transmission Connection Points forecast trend to the AEMO SA forecast trend, major customer variations were eliminated by removing the four Transmission Connection Points dominated by a single major customer (Whyalla, Port Pirie, Snuggery, North West Bend), and the SA Water Desalination Plant, prior to the reconciliation. The reconciliation process then modifies the Transmission Connection Point forecast thereby including the global impact of energy efficiency, PV and economic factors as forecast by AEMO for SA. The major customers are separately forecast based on the 2014 measured values and their advice of future plans.

Figure 20.31: Overview of the distribution system planning process



SOURCE: SA POWER NETWORKS 2014

Each Transmission Connection Point forecast trend is then reconciled with the forecast trend of the zone substations that are supplied from the Transmission Connection Point, similarly modifying the zone substation forecast to include the global factors forecast by AEMO.

The demand driven program for the 2015–20 RCP is based on the 2014 spatial demand forecast. All identified constraints and their timings as described in the Distribution System Planning Report AMP 1.1.01 and are either based on the 2014 measured load (where it exceeded the planning criteria) or the forecasts produced by the new forecasting tool (Acil Allen) at 10% and 50% PoE level (as applicable).

Our revised demand forecasting methodology and tools ensure a more transparent and improved spatial demand forecasting ability leading into the 2015–20 RCP.

Capacity Ratings
Major network assets are generally assigned a normal and emergency cyclic rating calculated in accordance with the relevant Australian Standard or Guideline. Normal ratings are applied when all network components are in service while emergency ratings are applied when one or more network components are out of service.

The normal rating is used for preservation of the asset's designed life, while the emergency rating is used for short term network contingencies when another portion of network has failed. Operating at the emergency rating will significantly shorten an asset's life, and cannot be sustained.

The cyclic rating takes into account the normal load profile seen by the asset and normally allows an increase in the asset's rating compared to its nameplate rating. For substation transformers, the normal and emergency ratings were reviewed in 2013 to include the change in load profile due to the connection of PV generation on the network. The typical reduction in net demand during the middle of the day when PV is generating typically increases the allowable cyclic rating by a small margin.

For further details on the forecasting methodology used for augmentation expenditure, refer to the DSPR AMP 1.1.01. Additionally, SA Power Networks is required under NER clause 5.13.2 and Schedule 5.8, to publish a Distribution Annual Planning Report (**DAPR**) that provides information about actual and forecast constraints on our network, details of these constraints and where they are expected to arise within the forward planning period. The DAPR is produced annually and must be published by the 1 December each year.

Costing methodology
In developing our augmentation driven capital plan, we have assigned each project to a works category relating to the component of the Network requiring augmentation, reinforcement or construction (eg Sub-transmission Network — Connection Point, Zone substation, Feeder, LV and Distribution Transformers, land).

The costs assigned to each project are determined using a set of standard component or unit costs expressed in nominal dollars. In our DSPR AMP 1.1.01, all values are expressed in 2013 dollars terms. In this document, all values have been expressed in June 2015 dollars.

Each project's total cost is derived using these standard construction components in order to ensure each project's costs are directly comparable to one another. These unit costs are revised annually and have been determined based on estimates for each unit using SA Power Networks' RealEst estimating tool. The costs developed within RealEst have been compared to the historic costs of actual projects (escalated to 2013 dollars) within the current RCP.

It is the intent of these unit costs that they represent all possible costs likely to be incurred by the business in undertaking a specific project. The unit costs values are intended to be all inclusive and including expenditure on non-field based activities such as design and third party approvals services.

Consideration of non-network solutions
When considering how best to address a network constraint, SA Power Networks must undertake a rigorous process to consider whether a non-network solution is applicable.

As required, we consider various non-network solutions when determining our preferred solution to address an identified constraint on our network. Examples of Demand Management solutions considered by us include:

1. power factor correction;
2. peak lopping embedded generation;
3. load transfers/balancing; and
4. amendment or creation of, Network System Support Agreements (**NSSA**) with customers to generate or curtail load on demand.

In addition, all projects estimated to cost in excess of $5 million are subject to the RIT-D in accordance with Section 5.17 of the NER. Where it is determined as a result of the Screening Test that publication of a Non-Network Options Report (**NNOR**) is warranted, a NNOR is created and issued for public consultation seeking alternative solutions to remedy the identified network constraint.

As explained in our 'current period performance', we have instituted one non-network solution at Bordertown to resolve an identified network constraint. This solution should defer the identified network constraint for a minimum of nine years.

In summary, it is believed that demand management initiatives have a limited potential to impact on our forecast, especially given SA Power Networks' performance of preliminary RIT-Ds for those projects in excess of $5 million, only two have suggested the adoption of a non-network solution may be economically viable. However, a number of demand management solutions are included as deferral solutions for smaller projects where preliminary analysis has shown they may be viable. Any successful demand management initiative is not expected to permanently eliminate the need for network reinforcement projects but rather defer them for some period of time (typically 1–3 years).

Occasionally a longer term deferral is possible in special circumstances. For example, Bordertown is located in the far east of South Australia near the Victorian border where constraints were identified for both the radial 33kV line supplying Bordertown zone substation and the transformer capacity at Bordertown zone substation itself. The non-network solution implemented has seen the construction of a third party owned, 4MW power station connected to Bordertown zone substation via an express 11kV feeder exit. This solution has deferred for at least nine years the construction of a second 33kV line from Keith to Bordertown, an upgrade of the Bordertown substation and an upgrade of the Keith Connection Point.

Forecast expenditure for 2015–20
SA Power Networks sub-transmission, distribution and low voltage networks augmentation program has been generated from requirements to upgrade our infrastructure resulting from changes to the ETC or as an output of SA Power Networks' planning process as detailed in our Distribution System Planning Report (**DSPR**) AMP 1.1.01.

SA Power Networks' augmentation expenditure for the 2015–20 RCP is $345.4 million (June 2015 $) and is summarised in Table 20.16. The forecast expenditure is a reduction of $90.6 million from the current period.

SA Power Networks is the sole licensed DNSP in South Australia. As discussed our DSPR AMP 1.1.01 is our assessment of our distribution system's capacity to meet forecasted demand over the ten years from 2015/16 to 2025/2026. The DSPR AMP 1.1.01 includes SA Power Networks' proposed plans for augmentation of the distribution network based on the information and estimates available at the time of publication. The project implementation timeframes have been based on the actual 2014 peak, 10% and 50% PoE load forecasts (as applicable).

The DSPR AMP 1.1.01 includes an overview of SA Power Networks' system planning methodology, 15 regional development plans covering SA Power Networks' connection points, sub-transmission lines, zone substations, distribution feeder exits and the low voltage network. Where relevant, details of system constraints and the proposed corresponding projects are included within these development plans.

Only those projects that have the most significant customer impact have been specified in detail. This generally includes those connection points, zone substations and sub-transmission line projects with an estimated value in excess of $5 million, whilst for all other expenditure categories (eg, voltage support, power factor correction, feeders etc), these have been specified in detail where the estimated value is in excess of $0.5 million.

The planning criteria used to develop this capacity plan are designed to meet the quality of supply (**QoS**) requirements of the Electricity Distribution Code (**EDC**) and maintain historic levels of network performance, security and reliability.

Future (non-committed) large customer connections, where the customer's maximum demand increase exceeds the forecasted annual load growth of the relevant network asset, are not included within the demand driven expenditure forecast. Network augmentations required for such projects will be managed in accordance with the EDC and SA Power Networks' customer connection processes in accordance with the National Energy Customer Framework (**NECF**) and SA Power Networks' customer connection charging manual on a case by case basis (refer to Section 20.7 of this chapter).

Whilst the majority of projects included in the 2015–20 RCP demand driven augmentation expenditure forecast are driven by capacity constraints, many are driven by constraints unrelated to future load growth for the asset(s) concerned. The drivers of the projects contained within our DSPR AMP 1.1.01 can be classified as either independent or dependent of the future load growth.

Table 20.16: SA Power Networks' forecast demand driven augmentation capital expenditure for 2015–20 (June 2015, $ million)

Demand driven augmentation expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Forecast	76.2	76.4	70.6	66.0	56.2	**345.4**

Those projects which may be categorised as being independent of future demand growth include:
a. ETC or ElectraNet augmentations;
b. Regulatory compliance (eg NER or EDC driven — includes QoS and management of the two way network);
c. Existing committed augmentations or those constraints where the planning criteria has already been breached;
d. Security driven augmentations; and
e. Strategic projects (eg land and easements).

Those projects which may be categorised as future demand growth dependent include:
a. New Greenfield developments (where little or no infrastructure exists today); and
b. General demand growth.

Of the project expenditure contained within the 2015–20 RCP, on average, 64% can be categorised as being independent of the load forecast. Figure 20.32 details the expenditure breakdown by forecast dependent and forecast independent project categories.

The forecast includes projects specifically aimed at deferring larger augmentation works through the use of demand management measures where a preliminary RIT-D investigation has suggested it is economical to do so. Augmentation projects are only considered where permanent load transfers are not capable of resolving the identified constraint.

The key investments in the demand driven augmentation categories are summarised below by driver. A consolidated list of all projects in the 2015–20 period and their driver is contained in the DSPR AMP 1.1.01.

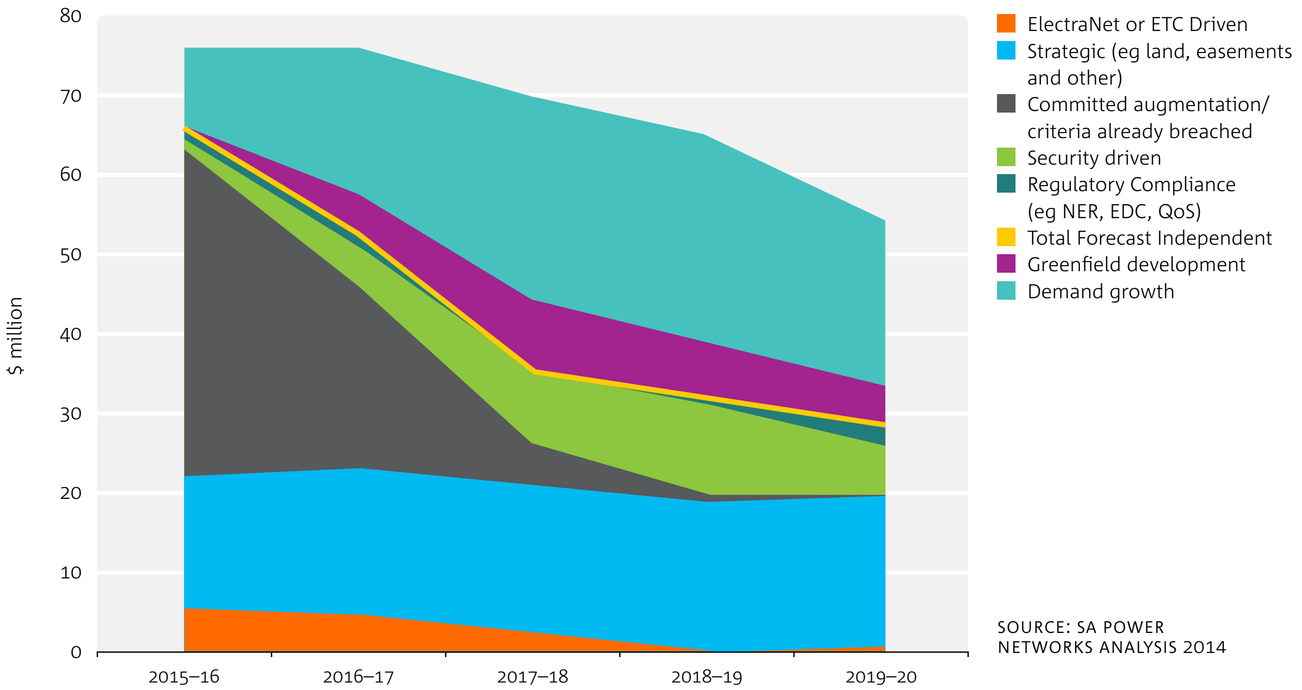
Committed projects
The following programs consist of committed projects categorised as being independent from future demand growth.

Electricity Transmission Code compliance
Transmission connection points are categorised according to the different levels of reliability and security of supply, as specified by ESCoSA within the ETC.

ElectraNet augments its connection point capacity based on joint planning with SA Power Networks and the connection point forecast annually produced by SA Power Networks in conjunction with ElectraNet. ElectraNet and SA Power Networks jointly maintain a Connection Point Management Plan (**CPMP**) which outlines the predicted timing and high level scope of new connection points, connection point upgrades and deferral solutions to connection point constraints via SA Power Networks' distribution network.

The 2015–20 RCP expenditure forecast only includes SA Power Networks' component of these connection point upgrades. Some of these upgrade works are mandated through the alteration of existing connection point's categorisation within the ETC or due to the timing of asset replacement works by ElectraNet approved by the AER as part ElectraNet's most recent Determination in 2013, as such, these works are required irrespective of the forecast demand at these sites.

Figure 20.32: Expenditure breakdown by forecast dependent and forecast independent project categories (June 2015 $)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

The current RCP includes expenditure for the establishment or upgrade of a number of ElectraNet's connection point substations, most notably the establishment of City West substation required significant augmentation on SA Power Networks' network, due to changes to the ETC in 2008. The 2015–20 RCP sees a return to more historical levels of ETC driven expenditure, in line with changes to the ETC in 2013. The forecast expenditure for ETC projects in the 2015–20 RCP is $14.1 million (June 2015 $). Table 20.17 lists the material ETC projects required in the 2015–20 RCP.

Table 20.17: Material ETC projects in the 2015–20 RCP (June 2015, $ million)

ETC projects greater than $5.0M	$M
Baroota 132/33kV connection point substation	5.0
Dalrymple 132/33kV connection point substation	4.6

LV and distribution transformers, including enabling two way network

Augmentation projects in this category require an upgrade of the LV and distribution transformer network. This is a large number of relatively small projects, which are triggered by customer complaints (low or high voltage). Projects are only committed after measurement at the customer's service point confirms the constraint. The forecast capital expenditure for remediation of projects is based on the average number of projects experienced over the last 4 years. Based on AEMO's SA global forecast we do not expect a change from recent history.

This driver also includes projects to assist in management of the transition from a one-way to a two way distribution network, driven by the dramatic growth in photovoltaic solar (**PV**) connections and the expected continued growth.

SA Power Networks has an obligation[63] to maintain supply voltage at customer premises within the range specified in AS60038. Until five years ago, it was straightforward to estimate voltage at the customer premises based on the topology of the network and the predictable flow of energy from centralised generation to customers with well-understood consumption profiles. Today, however, the network includes significant intermittent renewable generation distributed throughout the network in small-scale residential solar PV systems. This causes highly variable two-way power flows in the LV network, leading to significant localised swings in voltage.

Modelling undertaken in 2014 by Power Systems Consultants (**PSC**) examined the impact of increasing penetration of solar PV and other distributed energy resources on quality of supply at the customer premises. The study modelled fifteen typical LV feeders representing a cross-section of categories of supply area including underground, overhead and SWER. This study found across older areas of the LV network, existing network infrastructure and voltage regulation approaches, limit acceptable solar PV penetration to around 25% of customers (refer Attachment 13.2, SA Power Networks Consultancy Services for Impact of Distributed Energy Resources on Quality of Supply, PSC report).

Currently, the penetration of solar PV is more than 22% of all households, and is forecast to rise to 40% by 2020 (refer Attachment 5.3, Assessment of tariff options in South Australian, Energia). PSC's analysis confirms that many older distribution power lines are almost at saturation in terms of acceptable solar PV penetration and, without improved voltage regulation, many parts of the network will not be able to accommodate the forecast increase in solar PV during the 2015–20 RCP without triggering widespread customer power quality (**PQ**) issues. These may include customer-visible fluctuations in voltage, increased failure rate of customer appliances, and customers' solar PV inverters tripping off the network due to overvoltage on mild sunny days, eroding the benefit of their feed-in tariffs.

As explained in Chapter 13 of this Proposal, in the past, we have relied on customers to inform us of localised PQ problems, a reactive approach that has been effective and efficient given the relatively small number and nature of issues arising each year. Now, however, PSC's modelling forecasts widespread PQ problems, and a reactive approach would be imprudent.

If we are to continue to meet customer expectations as identified by our Customer Engagement Program, and regulated power quality standards through the 2015–20 RCP, we require investment to establish the capability to monitor PQ through the LV network.

In the 2015–20 RCP, SA Power Networks intends to undertake a targeted LV monitoring program to deploy grid-side monitoring devices installed at LV transformers, SWER lines and substations, to improve capacity planning and power quality management across a number of areas of the network, in particular in rural areas. These grid-side monitoring initiatives will establish permanent end-of-line capacity and power quality monitoring in rural areas of the network, as well as addressing some immediate problem areas where high solar penetration is already causing increased volumes of customer complaints.

63 Electricity Act and Regulations, Part 10, Division 1, Section 46 — Quality of Electricity Supply and EDC Section 1.1.5

The forecast expenditure for these LV and Quality of Supply (**QoS**) projects in the 2015–20 RCP is $91.2 million (2015 $). Table 20.18 lists the material LV and QoS projects required in the 2015–20 RCP.

Table 20.18: Material LV and QoS projects in the 2015–20 RCP (June 2015, $ million)

Low voltage and Quality of Supply programs and projects	$M
LV distribution transformers	55.0
LV two way network	20.4
HV regulation (PQ visibility, voltage control, Code compliance)	8.3
Long term transformer monitors (PQ visibility, Code compliance)	8.0

As the broader population of smart-capable meters grows under our new and replacement program, we also propose to prudently install telecommunications modules in selected meters in older urban areas of the LV network in order to establish a strategic platform for PQ monitoring at the customer supply point in these areas. This is described further in Section 20.6.3 of this chapter.

Planning Criteria exceeded
This program consists of projects where the Planning Criteria was exceeded in 2014. Demonstrated demand has exceeded the network planning criteria and customer load is now at risk until projects are implemented to resolve the network constraint. Many of these projects are in progress and are expected to be completed in the 2015/16 year.

The forecast expenditure for planning criteria exceeded projects in the 2015–20 RCP is $69.5 million (June 2015 $). Table 20.19 lists the material planning criteria exceeded projects required in the 2015–20 RCP.

Table 20.19: Material planning criteria exceeded projects in the 2015–20 RCP (June 2015, $ million)

ETC projects greater than $5.0M	$M 2010–15	$M 2015–20
Two Wells 66/11kV substation and 66kV sub-transmission power line	5.1	5.0
McLaren Flat 66/11kV substation	2.6	2.6
Dorrien 33/11kV substation	2.8	2.8
Gawler Belt 33/11kV substation	2.6	2.5
Port Noarlunga to Aldinga double circuit 66kV sub-transmission power line	0.7	15.0

Security
Projects within this category are not growth driven, but rather to maintain existing levels of reliability or improve the security of the network where a positive market benefit based on RIT-D can be demonstrated. A preliminary RIT-D assessment has been performed on present load levels rather than forecast levels and demonstrates a positive market benefit.

These network augmentations are intended to either minimise the duration of network outages or prevent cascade outages within the network.

We have one material security project proposed to improve the security of supply to 28,900 customers on the Fleurieu Peninsula Network by the construction of a new 66kV sub-transmission power line between Myponga and Square Waterhole substations. A non-network solution is also being considered to resolve this constraint, refer to DSPR AMP 1.1.01.

The forecast expenditure for the identified capacity driven security projects in the 2015–20 RCP is $33.0 million (June 2015 $). Table 20.20 lists the material security of supply project required in the 2015–20 RCP.

Table 20.20: Material security projects in the 2015–20 RCP (June 2015, $ million)

Security projects greater than $5.0M	$M
Myponga to Square Waterhole 66kV sub-transmission power line	21.7

Land, easements, and other
In order for us to adequately plan for the future, we may need to make strategic land and easements acquisition, prior to their actual need. This requirement is to ensure that both suitably located and sized areas exist for future network augmentation requirements and to ensure new regions can be planned by the responsible jurisdiction (eg SA Government and/or local council) in a prudent and efficient manner.

This is particularly the case within new underground residential development (**URD**) areas. Whilst these augmentations are ultimately demand and therefore forecast driven, the acquisition of these sites is required prior to this time. Given the size requirements of substations and statutory easement widths required for new sub-transmission lines, it is considered prudent planning for SA Power Networks to procure such sites when land division developments are approved. In addition, it is also prudent to procure land in advance of forecast requirements to ensure delays to the required network augmentation do not arise in trying to procure such land holdings from the relevant land holders on a just in time basis.

The expenditure forecast in the 2015-20 RCP for land, easements, and other is required for the following:

- greenfield projects proceeding in the 2015-20 RCP;
- network security where land and easements required to expand the distribution network beyond 2020, may be at risk of development;
- the development of systems, processes, education and support materials for the implementation of the Flexible Load Strategy, discussed further in chapters 13, 21 and Attachment 20.34, and
- the development and trial of the substation digitalisation standard IEC61850

The forecast expenditure for land, easements and other is $12.9 million (June 15 $)

Future demand growth
The following programs consist of projects which may be categorised as future demand growth dependent.

New greenfield customer developments
New customer developments are forecast to occur in a region with little or no distribution network today and will require a major network expansion to supply. This only applies to regions where a strong indication of customer development will occur in the next RCP and involves multiple customers and large scale residential sub divisions and is consistent with the State Government's 30 year growth plan. This portion of the forecast capital expenditure does not include the HV power line, distribution transformer and LV power line connection assets, these are included in customer connections.

The forecast expenditure for greenfield projects in the 2015–20 RCP is $25.9 million. Table 20.21 lists the material greenfield projects required in the 2015–20 RCP.

Table 20.21: Material greenfield projects in the 2015–20 RCP (June 2015, $ million)

Greenfield customer development projects	$M 2015–20	$M 2020–25
Gawler East 66/11kV substation	12.1	-
Evanston Gardens 66/11kV substation	2.6	7.3

Planning criteria forecast to be exceeded
This program consists of projects where it has been forecast that the load will exceed the Planning Criteria in the 2015–20 RCP. This portion of the expenditure is dependent on the spatial demand forecast.

The demand driven expenditure is forecast to be similar to the current RCP as the global SA demand forecast has also been forecast to remain relatively flat. It is important to note that whilst SA Power Networks forecasts minimal global demand increases across our network, there are localised areas of growth requiring network augmentation to be undertaken to ensure compliance with NER 6.5.7(a) objective 1. SA Power Networks is forecasting regional growth in the northern and southern suburbs (new housing developments) where time of peak has already reached 7:00pm (and any future PV will have minimal impact) and a number of localised zone substations, such as Campbelltown, Clare and Aldinga (new housing developments or infill housing). The full details of demand driven expenditure are in our Distribution System Planning Report AMP 1.1.01.

The forecast expenditure for planning criteria forecast to be exceeded projects in the 2015–20 RCP is $98.7 million. Table 20.22 lists the material planning criteria exceeded projects required in the 2015–20 RCP.

Table 20.22: Material planning criteria exceeded projects in the 2015–20 RCP (June 2015, $ million)

Planning criteria forecast to be exceeded projects greater than $5.0M	$M 2015–20	$M 2020–25
Clare 33/11kV substation upgrade	6.1	-
Glynde/Campbelltown 66/11kV substation	18.4	-
Aldinga/Maslins Beach 66/11kV substation	4.9	4.1
Snuggery to Robe (Non Network solution)	9.9	-

Summary of demand driven augmentation
Table 20.23 below details the percentage proportion per driver of the total demand driven augmentation expenditure forecast for the 2015–20 RCP.

Table 20.23: Percentage proportion of the total demand driven augmentation expenditure forecast per driver

Driver	Proportion of % of the 2015–20 demand driven expenditure forecast
Committed programs	
ETC compliance	4%
LV and Dist TFs including enabling 2 way network and Code compliance	26%
Planning criteria exceeded	20%
Security	10%
Land, easements, and other	4%
Future growth	
Greenfields	7%
General growth	29%

20.6.2
Reliability expenditure

This section should be read in conjunction with Chapter 10 'Responding to severe weather events', and the referenced attachments.

Reliability capital expenditure is required to maintain our reliability performance so that we achieve the ESCoSA service standards for reliability as detailed in the EDC and in accordance with the requirements of our Distribution Licence and the capital expenditure objective 6.5.7(a)(2).

Although SA Power Networks' average underlying performance remains relatively stable, regulatory expenditure targeted for reliability performance management is essential to maintain the underlying reliability performance.

Reliability expenditure is limited to the installation of new assets or alteration of existing assets. Where assets are replaced on a like for like basis or refurbished that expenditure has been included in the replacement capital expenditure discussed in Section 20.5.

The reliability forecast expenditure for the current RCP is $28.9 million (nominal), $3.7 million above the AER allowance of $25.2 million (nominal), refer Table 20.24.

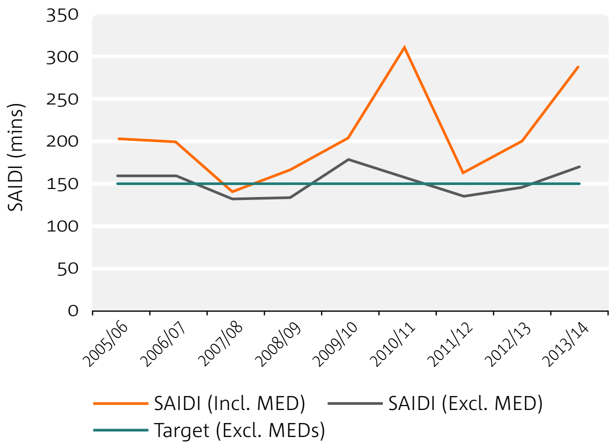
Overall the reliability expenditure for the current RCP was reasonably consistent with the AER allowance, with the exception of the higher expenditure in 2011/12.

This was in response to the emergence of extreme severe weather events in 2010/11, primarily due to lightning storm related interruptions. Work commenced on re-insulating some of the highest lightning prone sub-transmission lines with poly resin insulators, as a trial to measure the effectiveness insulator upgrades have on hardening the network against storms, specifically lightning.

Whilst the trial proved effective for the locations involved, our overall reliability performance continued to be impacted by the increasing frequency of lightning events (see Figure 20.33).

SA Power Networks' forecast reliability expenditure for the 2015–20 RCP is summarised in Table 20.25.

Figure 20.33: SA Power Networks' network reliability performance with and without MEDs



SOURCE: SA POWER NETWORKS ANALYSIS 2014

Generally the reliability program targets operational flexibility and protection of the network to minimise the impact of supply outages. Reliability expenditure is also required to maintain a fleet of emergency response plant including generators and equipment that assist with maintaining supply to critical customers during outages and to maintain supply during planned maintenance where feasible.

Reliability expenditure is also targeted on areas of the network that are worst performing and much of which is regionally based. There are small remote communities whose reliability levels significantly exceed ESCoSA's service standards. As only a small number of customers are affected, the lower service levels they receive do not contribute materially to the overall reliability performance outcomes of the region. We are required to report to ESCoSA actions to improve the reliability of these areas.

Under 6.5.7(e) (5A) of the NER, the AER must have regard to the extent to which the capital 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.

Table 20.24: Comparison of reliability AER allowance and actual/forecast capital expenditure ($ million, nominal)

Reliability expenditure	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Allowance	5.0	4.9	5.0	5.1	5.2	**25.2**
Actual/forecast	5.6	9.8	4.9	3.7	5.0	**28.9**

Table 20.25: SA Power Network's forecast reliability capital expenditure for 2015–20 (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Reliability expenditure	9.1	11.1	12.2	13.1	13.3	**58.8**

The majority of our customers who responded to our TalkingPower program have told us they are satisfied with their current levels of reliability, however as explained in Chapter 10 of this proposal, our customers have said we should invest more to harden parts of our network supplying communities that experience extremely poor reliability, primarily as a result of severe weather events.

SA Power Networks, in accordance with the current jurisdictional reliability service standard framework, is required to use best endeavours to meet overall regional reliability targets, however due to several extreme severe weather events during 2010/11, our overall performance during 2010/11 was poor. As a result ESCoSA has and will specifically focus on our performance during MEDs in the upcoming 2015–20 RCP. It is ESCoSA's expectation that our performance on MEDs will not decline but improve.

We are proposing to expand our program of reliability work by investing in strategies to reduce the impact of the increasing number and severity of major weather events, and returning overall reliability to average levels for those customers consistently worst served. Refer to Table 20.26 for details of our proposed reliability program for the 2015–20 RCP.

Given the increasing age profile of our assets and the expected continuing trend of severe weather events as predicted by the Australian Bureau of Meteorology (**BoM**) (refer Attachment 10.1), expenditure of $28.1 million (June 2015 $) is necessary to continue our reliability programs: to maintain the underlying network performance (excluding MEDs); deliver a neutral overall STPIS result by the end of the 2015–20 RCP; achieve reliability performance standards as detailed in the Service Standard Framework; and address poor customer service levels as specified in the Reliability Management AMP 2.1.01.

To mitigate the deterioration in our overall reliability performance (including MEDs), we need to harden our network in locations that are consistently affected by lightning and wind storms. This will cost $17.0 million (June 2015 $) and excludes expenditure on low reliability feeders and Hawker/Elliston.

There are communities whose customer service performance consistently does not meet regional targets set by ESCoSA mainly due to the impact of severe weather, as these regions are supplied by single radial power lines that can be more than one hundred kilometres in length. These power lines are more prone to impacts from severe weather due to their length and when faults do occur, the supply interruption is significantly longer owing to the time it takes to locate and remediate the fault.

SA Power Networks is conscious of the customer service impacts on these communities. It is considered unacceptable to consistently receive reliability vastly inferior to the regional average.

There are 31 low reliability power lines that have been reported to ESCoSA in our Annual Operational Performance Report. We propose to harden the network against lightning and storms for 30 of these power lines at a cost of $8.5 million (June 2015 $) (refer Reliability Management AMP 2.1.01).

For the 31st power line, a trial micro-grid solution will be undertaken. The microgrid solution consists of combined distributed storage and centralised storage at a cost of $2.8 million (June 2015 $), as a future alternative option to remediate reliability or defer augmentation to remote communities.

To improve the network infrastructure to two communities whose reliability performance consistently and significantly exceeds the reliability targets for their regions, being Elliston on the Eyre Peninsula and Hawker in the Flinders Ranges, remediation of the power lines supplying these communities is required at a cost of $2.4 million (June 2015 $) (refer Reliability Management AMP 2.1.010).

The Hawker and Elliston program has been developed as a direct result of our customers concerns raised in our customer engagement workshops regarding Elliston and Hawker. These workshops have reaffirmed the requirement for a reliable supply comparable with other townships within their region.

Table 20.26: Reliability program for the 2015–20 RCP (June 2015, $ million)

Reliability	Description	$M	AMP
Maintaining reliability	Remedial works undertaken to maintain the overall reliability of the network	28.1	AMP 2.1.01
Hardening the network	Remedial works to mitigate the impact of increasing number and severity of severe weather events	17.0	AMP 2.1.01
Low reliability feeders	Remediation of the consistently worst performing power lines	8.5	AMP 2.1.01
Hawker and Elliston	Remediation of the power lines that supply Hawker and Elliston	2.4	AMP 2.1.01
Microgrid trial	Trial of a combined distributed storage and centralised storage microgrid solution	2.8	AMP 2.1.01 Smarter Network Strategy
Total		**58.8**	

20.6.3
Strategic projects

This section should be read in conjunction with Chapter 9 'Keeping the power on for South Australians' and the referenced attachments.

The strategic expenditure category primarily includes a number of one-off strategic projects aimed at ensuring the security of supply of the network. The strategic forecast expenditure for the current RCP is $78.2 million ($ nominal), $7.2 million above the AER allowance of $71.0 million ($ nominal), refer Table 20.27.

In the current RCP the following strategic projects have been undertaken:

- National Electricity Rules (**NER**) compliance, including for load shedding and ensuring protection clearing times are compliant;
- Acquired strategic land for future substations;
- Expanded our Network Operations Centre (**NOC**) and commissioned an offsite back up NOC;
- Implemented the first stage of our Advanced Distribution Management System (**ADMS**) in our NOC;
- Installed SCADA controlled switches on priority bushfire boundaries. This program is planned to continue into the 2015–20 RCP;
- Extended SCADA to priority country substations. This program is planned to continue into the 2015–20 RCP; and
- Collection of condition information on our priority assets (poles, conductor, and substation transformers and circuit breakers) required for our CBRM model.

Variations to the allowance, year by year, were due to the timing in implementing the ADMS project where the major portion of expenditure will be in 2014 and 2015.

The factors that resulted in the implementation delays of ADMS were related to a review of the base data required for the establishment of the new SCADA system taking longer than forecast. A decision was taken to review and cleanse historical data to ensure the new SCADA system consisted of a dataset that was reflective of the actual devices and configuration in the field.

SA Power Networks' strategic expenditure forecast for the 2015–20 RCP is summarised in Table 20.28.

The network strategic program for 2015–20 is a combination of the continuation of existing strategic projects consistent with historic expenditure, and new projects. Refer to Table 20.29 for details of our proposed strategic security of supply program for the 2015–20 RCP.

The new programs are described in further detail below.

Ensuring security of supply to Kangaroo Island

SA Power Networks, the South Australian Government, the Kangaroo Island Council and our customers generally, have specific concerns regarding our ability to maintain security of supply to Kangaroo Island if the ageing undersea cable was to fail. All parties support action to maintain the reliability and security of that part of the distribution system.

Kangaroo Island is supplied via a radial sub-transmission line consisting of 50km of 66kV sub-transmission line between Willunga and Cape Jervis, and 90km of 33kV sub-transmission line between Cape Jervis and Kingscote, including a 15km section of 33kV undersea cable between the mainland and the island.

The undersea cable was installed in 1993 and is approaching the end of its predicted 30 year life. In this case, SA Power Networks must use the predicted service life of the undersea cable as an indicator of the condition of the cable because it is very difficult to inspect the actual cable due to the depth at which most of the cable is laid. Relying upon the predicted service life is reasonable and prudent in this case due to the materiality of the impact upon the security of supply to the Island if the cable was to fail.

In the event the existing cable failed before the new cable was installed, the island will be reliant on limited diesel generation for more than 12 months if the cable can be repaired, or up to 24 months if the cable has to be replaced. The generation and support cost to supply Kangaroo Island for a minimum of 12 months while the cable is being repaired is estimated to exceed $31.6 million (June 2015 $).

Table 20.27: Comparison of strategic AER allowance and actual/forecast capital expenditure ($ million, nominal)

Strategic expenditure	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Allowance	11.5	16.4	17.7	15.3	9.9	**71.0**
Actual/forecast	6.5	12.4	18.1	25.7	15.4	**78.2**

Table 20.28: SA Power Networks' strategic capital expenditure for 2015–20 (June 2015, $ million)

Strategic expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Forecast	14.4	25.1	32.5	18.2	8.4	**98.5**

Table 20.29: Strategic program for the 2015–20 RCP (June 2015, $ million)

Strategic	Description	$M	AMP/Business case
Kangaroo Island undersea cable	Replacement of the aged Kangaroo Island undersea cable	47.2	AMP 2.1.03
Network control	Continuation of our long term program to extend SCADA to our country substations and targeted high voltage reclosers and sectionalisers for operational requirements	27.4	AMP 2.1.02 Smarter Network Strategy
Network monitoring	A new program to install communications modules in targeted smart ready meters to enable a two way network	16.1	Tariff and Metering business case Smarter Network Strategy
Asset condition monitoring	Continuation of our long term program to extend the CBRM methodology to the following asset classes: ground level switchgear, underground cables, protection and control, reclosers and sectionalisers	6.0	AMP 3.0.01
NER compliance	Undertaking load shedding as required and ensuring protection clearing times are compliant	1.8	AMP 3.2.14
Total		**98.5**	

During this repair period, reliability performance to Kangaroo Island will significantly deteriorate, adversely impacting on tourism, business, the community and local economy. The National Value of Customer Reliability (**VCR**) is used to reflect how much customers are willing to pay to have secure supply. The VCR cost incurred for not having a secure supply to Kangaroo Island is estimated to be $3.4 million (June 2015 $).

Preventative asset replacement when a cable is near the end of its design life is considered the most prudent and efficient approach. A Net Present Value (**NPV**) analysis has been undertaken that supports the installation of a new cable by 2018. The existing undersea cable would have to last beyond 2034 (11 years past the cable's design life and 19 years longer than the original undersea cable) for this to become the most cost effective solution.

As required by the NER, we must ensure we maintain a secure supply to the Island. The proposed solution is to install a second undersea cable between Fisheries Creek, near Cape Jervis and Cuttlefish Bay, near Penneshaw, by 2018 at a cost of $47.2 million (June 2015 $) as detailed in our Kangaroo Island Sub-transmission Electricity Supply AMP 2.1.03.

The Minister for Mineral Resources and Energy along with the Kangaroo Island Council both provided submissions supporting the replacement of the undersea cable supplying Kangaroo Island, (refer Chapter 9, and Section 9.3.3).

Enabling a two way network

As explained in Section 20.6.1, LV and Quality of Supply modelling undertaken by consultant PSC has shown that, without increased visibility of the LV network, the current approach to voltage regulation may be unable to maintain the regulated quality of supply standards at customer premises under the level of solar penetration forecast for the 2015–20 period.

In urban areas that have older overhead LV network infrastructure, PSC's modelling indicates that high solar penetration can cause significant variations in voltage between the LV transformer and the end of an LV feeder. For these areas, monitoring at the LV transformer is not sufficient, and our approach is to establish monitoring at a number of points along the length of each LV feeder.

As the broader population of 'smart-capable' meters grows under our new and replacement program, we propose to prudently install telecommunications modules in meters for power quality (**PQ**) monitoring at the time of meter replacement for a targeted subset of new and replacement meters located in urban areas with older LV network infrastructure. Through this long-term approach we will, during the 2015–20 RCP, progressively establish capability to monitor PQ within these areas of the LV network at substantially lower cost than installing dedicated monitoring devices. This is the platform that will enable the ongoing management of power quality in these areas through 2020 and beyond.

We propose specifically to establish three measurement points per LV feeder in our target areas, and to use three phase meters in order to measure power quality across all phases at each location. Based on the current proportion of three phase meters across our customer base, we anticipate that approximately 15% of the new and replacement meters installed per annum will be candidates to be enabled as PQ monitors. This gives an installation rate of 10,000 telecommunications modules per annum, which will achieve our goal of three monitoring points per LV feeder across urban overhead network areas by the end of 2021.

For further details, refer to the Tariff and Metering business case (Attachment 14.3).

20.6.4 Environmental

Environmental expenditure is required to ensure prudent management of environmental risks to comply with Environment Protection Authority (**EPA**) legislation, regulations, policies and standards and to meet the requirements of NER 6.5.7(a)(2).

The environmental actual/forecast expenditure for the current RCP is $8.7 million ($ nominal), $7.4 million below the AER allowance of $16.1 million ($ nominal), refer Table 20.30.

There were initial delays in the commencement of the distribution power line environmental program in the current RCP, as a result of taking longer than forecast to engage resources to scope specific projects.

Some distribution power line and substation environmental remediation has been undertaken in conjunction with larger replacement or augmentation projects with the costs being included in these projects.

We have taken this lower environmental expenditure into consideration in our forecasting of the environmental capital expenditure for the 2015–20 RCP. There is also a special project to remediate Mannum Town substation.

SA Power Networks' Environmental forecast expenditure for the 2015–20 RCP is summarised in Table 20.31.

The distribution environmental management program is a program that consists of environmental related capital and operating expenditure resulting from periodic asset inspections, as specified in the Distribution Environmental AMP 4.1.03.

The environmental program is a continuation of programs of work consistent with historic expenditure, and new work in accordance with EPA requirements. Refer to Table 20.32 for details of our proposed environmental program for the 2015–20 RCP.

The *Environment Protection Act 1993* and the Environment Protection (Water Quality) Policy 2003 places a legal responsibility on us to not undertake any activity that pollutes, or has the potential to pollute, the environment unless we take all reasonable and practicable measures to prevent or minimise any resulting harm. The capital portion of the distribution environmental program is $2.8 million (June 2015 $), and is primarily to address oil filled assets that have been classified as medium or high risk through formalised assessment criteria. This process is in alignment with our regulatory obligations and includes but is not limited to: proximity to a sensitive receptor (eg a watercourse/body, shallow groundwater), land use (horticulture/agriculture, residential properties, grazing land) and areas considered to be of high environmental benefit.

An important element of this program is the identification and rectification of those oil filled assets that display visual signs of failure (eg severe corrosion or leakage). SA Power Networks has determined that this prudent and precautionary approach is reflective of our obligations under the *Environment Protection Act* as it seeks to reduce the risk of failing equipment causing significant environmental impact. Furthermore, the business has determined that the avoidance/minimisation of the costs associated with a 'reactionary' approach to oil filled asset ruptures, including emergency response, clean up and possible EPA penalties provides better longer term outcomes for consumers. The forecast was derived using efficient historic costs.

Further, our Substation Oil Containment AMP 4.1.01 has been developed to address environmental risk by auditing, monitoring, remediating and retrofitting substations, in line with the EPA requirements.

SA Power Networks currently has 404 substations with oil filled equipment. Presently, only 25% of the 404 sites are equipped with adequate oil containment systems, presenting an environmental risk at those sites without oil containment.

Table 20.30: Comparison of environmental AER allowance and actual/forecast capital expenditure ($ million, nominal)

Environmental expenditure	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Allowance	2.7	3.2	3.4	3.4	3.5	**16.1**
Actual/forecast	0.9	2.0	1.8	1.3	2.8	**8.7**

Table 20.31: SA Power Networks' environmental capital expenditure for 2015–20 (June 2015, $ million)

Environmental expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Forecast	4.2	4.2	2.4	2.3	2.4	**15.5**

Table 20.32: Environmental program for the 2015–20 RCP (June 2015, $ million)

Environmental	Description	$M	AMP
Environmental management	Long term program to replace aged or corroded oil filled distribution equipment, adjacent 'sensitive receptors' (areas representing a high risk of potential or actual environmental harm through a pollution event, eg in lakes and rivers)	2.8	AMP 4.1.03
Substation oil containment	Long term program to install oil containment systems on high risk equipment	7.9	AMP 4.1.01
Substation noise abatement	Long term program to install noise abatement measures to rectify targeted substation transformers that exceed EPA noise limits	1.0	AMP 4.1.05
Mannum Town Substation	A specific project to remediate Mannum Town substation to mitigate the potential environmental contamination of the River Murray	3.8	AMP 4.1.06
Total		**15.5**	

The Environment Protection Act along with the *National Environment Protection (Assessment of Site Contamination) Measure (1999)* provides a framework for investigating and determining the risks associated with contamination on a site. SA Power Networks is also required by the EPA to bund transformers containing oil that may pose a risk of pollution to the surrounding environment. The EPA 'Bunding and spill management Guideline' was revised in 2012 and now includes more stringent requirements for bunds and spill containment systems.

We propose to continue with our current level of annual expenditure to prudently remediate high risk sites by 2020, and all medium risk sites by 2025.

The *Environmental Protection (Noise) Policy (2007)* specifies the maximum allowable continuous noise levels dependent on land use and the time of day. The limits take into account the low frequency emissions that are characteristic of substation transformer noise.

Our Substation Noise Control AMP 4.1.05 has been developed to address noise related emissions from our substations, in line with our EPA obligations.

The Mannum Town substation was constructed in the early 1950s. It has two 2.5MVA transformers, and both have a long history of oil leaks, causing significant contamination of the soil.

During 2014, oil leaks were repaired on both transformers, and soil testing was undertaken to determine the extent of contamination. A high concentration of oil is present to a depth of four metres, and there is a significant risk of ground water contamination without immediate intervention. This is of major concern given the location is in close proximity to the River Murray. As an interim measure until the permanent solution is implemented, the oil leaks have been repaired and a synthetic liner has been placed around the transformers, ground water monitoring is being undertaken at regular intervals.

In accordance with our obligations, SA Power Networks has notified the EPA of our potential to cause 'Material Environmental Harm'. SA Power Networks is obligated to take action to prevent further contamination of the groundwater and remediate the site.

The Mannum Town AMP 4.1.06 documents SA Power Networks' strategy for the replacement of Mannum Town Substation and environmental remediation of the property to avoid any further contamination of ground water, in line with our EPA obligations.

The replacement of Mannum Town Substation is the most prudent and efficient option as it is reflective of the best course of action to remediate the environmental contamination, whilst maintaining security of supply.

20.6.5
Safety

This section should be read in conjunction with Chapter 11 'Safety for the community' and the referenced attachments. Chapter 11 describes the key safety risks to the community from network assets. In particular, fire starts from electricity network assets represents a key risk for SA Power Networks and the community and this risk continues to rise.

Augmentation safety expenditure is specifically required to ensure prudent management of the range of safety risks in order to maintain the safety of the distribution system through the supply of SCS, the fourth objective in clause 6.5.7(a) of the NER. This expenditure requires the installation of new assets or the replacement of existing assets with improved technology, whereas safety replacement expenditure is for replacement of 'like for like' assets and has been included in the replacement capital forecast discussed earlier.

The safety expenditure forecast in the current RCP is $16.9 ($ million, nominal), $4.5 million above the AER allowance of $12.4 ($ million, nominal), refer Table 20.33.

The forecast variance in safety expenditure in the current RCP has arisen due to the commencement of bushfire mitigation measures based on the outcomes of the Victorian Bushfire Royal Commission (**VBRC**) and the Victorian Power Line Bushfire Safety Taskforce (**PBST**), to ensure SA Power Networks continues to operate in accordance with good electricity industry practice, having regard to comparative networks elsewhere in Australia.

In the 2010–15 RCP we have commenced installing reclosers on bushfire boundaries. In addition, we have undertaken significant analysis of bushfire risk specific to South Australia. We engaged consultants Willis to undertake maximum probable loss studies to determine the areas of the State that are at the most risk from bushfires. We engaged Jacobs (Jacobs formerly SKM), to review our historic fire start data and the outcomes of the VBRC, to develop a prudent program of bushfire mitigation strategies. Taking into consideration the results of the maximum probable loss studies and the Jacobs review, we have developed an extensive model that prioritises all of our power lines in order of fire start risk to ensure our bushfire program is managed prudently and efficiently.

SA Power Networks' Safety forecast expenditure for the 2015–20 RCP is summarised in Table 20.34.

In the 2015–20 RCP safety expenditure is focussed on activities that will maintain the appropriate safety of our network for our workforce and the general public, as required by the fourth objective in clause 6.5.7(a) of the NER. The expenditure also includes initiatives developed in collaboration with our customers as part of our Customer Engagement Program.

The safety program is a combination of new projects and a continuation of the existing programs, totalling $319.5 million (June 2015 $). Refer to Table 20.35 for details of our proposed safety program for the 2015–20 RCP.

Improving community safety in HBFRAs

The risk of fire ignition from electricity assets is well known. Equally well known is that the total elimination of this risk would require expenditure which is cost prohibitive. SA Power Networks is committed to targeted investment to reduce the risk of bushfire as far as practicable using a prudent allocation of funds. That is, our approach is to mitigate the risk of bushfire, recognising that it is not financially prudent to seek to eliminate this risk.

While historically bushfire risk management by SA Power Networks has been effective, an analysis of climatic trends sourced from the Bureau of Meteorology (refer to the Climate extremes analysis for SA Power Networks operations report, Attachment 10.1), predicts that in South Australia, the conditions most conducive to intense and damaging fires are occurring on a more frequent basis. Given the outcomes of the Black Saturday bushfires of 2009, it is critically important that prudent bushfire mitigation efforts are undertaken having regard to this forecast increase in risk.

As explained in Chapter 11 'Safety for the community', SA Power Networks engaged Jacobs, to identify a prudent and targeted bushfire program aimed at achieving the greatest level of reduction in fire risk, relative to the investment involved. The program is also designed to ensure SA Power Networks continues to operate in accordance with good electricity industry practice, having regard to comparative networks elsewhere in Australia.

Table 20.33: Comparison of safety AER allowance and actual/forecast capital expenditure ($ million, nominal)

Safety expenditure	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Allowance	1.4	2.3	2.8	2.9	3.0	**12.4**
Actual/forecast	0.5	1.7	1.0	1.3	12.3	**16.9**

Table 20.34: SA Power Networks' safety capital expenditure for 2015–20 (June 2015, $ million)

Safety expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Forecast	33.2	58.8	69.0	76.5	81.9	**319.5**

Table 20.35: Safety program for the 2015–20 RCP (June 2015, $ million)

Safety	Description	$M	AMP/Business case
Bushfire mitigation program	Based on the outcomes of the VBRC and PBST, a new program to manage the increasing risk of bushfires starting from our infrastructure in high bushfire risk areas and to provide secure power supply to Bushfire Safer Places	220.1	Recommended Bushfire Risk Reduction Strategies Bushfire mitigation business case Metered mains business case GFN business case
Substation fencing and security	Long term program to remediate inadequate substation security fencing and security systems	11.7	AMP 5.1.03
Substation earthing	Long term program to remediate unsafe substation earthing systems	7.3	AMP 3.2.10
Substation lighting	Long term program to remediate substation lighting to ensure safe substation access for our workforce	2.4	AMP 5.1.05
CBD fault level control	Completion of the program to remediate dangerous fault levels on our 11kV CBD network	0.5	AMP 2.1.07
Road safety program	A new program to address road safety hazards from our power lines in high risk locations	77.5	Undergrounding for road safety business case
Total		**319.5**	

The programs identified as a result of this analysis are set out below:

- progressive replacement of ageing recloser devices with modern SCADA controlled devices which can be operated remotely, refer Bushfire Mitigation Business Case (Attachment 20.45);
- targeted replacement of bare 11kV and 33kV with underground cables to mitigate fire start risk in the highest risk areas, and to improve community safety by ensuring security of supply to targeted CFS Bushfire Safer Places, refer Bushfire Mitigation Business Case;
- replacement of Rod Air Gaps (**RAGs**) and Current Limiting Arcing Horns (**CLAHs**) with surge arrestors, refer Bushfire Mitigation Business Case;
- investigation of the potential future use of ground fault neutralising technology, refer GFN Business Case (Attachment 20.70);
- scoping of the extent of metered mains installations in need of reconstruction and commencement of reconstruction works, refer AMP 3.1.08; and
- improved backup protection on the rural network in accordance with AMP 3.2.14.

The analysis underpinning the identification of these programs is set out in the Jacobs report 'Recommended Bushfire Risk Reduction Strategies', which is provided as Attachment 11.8 to this Proposal.

During our Customer Engagement Program, customers and stakeholders overwhelmingly reinforced that the community places very significant priority on bushfire risk management and accordingly expect SA Power Networks to adopt appropriate bushfire risk management practices, commensurate with good electricity industry practice, as identified from the VBRC and PBST outcomes and subsequent Victorian Government investigations. Chapter 11, Section 11.2.1, clearly outlines the extent of customer support including through customers' Willingness to Pay for targeted undergrounding works in BFRAs. Our Bushfire Risk Management program represents a prudent approach at a forecast cost of $220.1 million (June 2015 $).

Also relevant to the Bushfire Risk Management program are those objectives regarding maintaining the quality, reliability and security of SA Power Networks' SCS (clauses 6.5.7(a)(3) and 6.5.6(a)(3) of the NER).

The Jacobs 'Bushfire Risk Reduction Strategies' report (Attachment 11.8) outlines the program in further detail and the 'Bushfire Mitigation' summary report (Attachment 20.50), demonstrates in greater detail that:

1. bushfire mitigation is critical to maintaining the quality, reliability and security of SA Power Networks' SCS;
2. the proposed bushfire mitigation strategies are a cost efficient way of achieving that objective;
3. a prudent operator in SA Power Networks' circumstances would implement the proposed strategies; and
4. the forecast capital and operating costs associated with the proposed strategies are realistic expectations of those costs.

Taking into consideration the power line undergrounding program, a resulting reduction in vegetation clearance costs has been taken into account, refer to Chapter 21, Section 21.6.3.

Underground for road safety

The AER must have regard to, among other things, the extent to which the Proposal includes expenditure to address the concerns of electricity consumers as identified through engagement with electricity consumers (clauses 6.5.7(e)(5A) and 6.5.6(e)(5A) of the NER).

Our customers have told us that they have a high level of concern about community safety and want SA Power Networks to undertake strategic investment that focuses on public safety.

As highlighted in Chapter 11, during our collaborative strategic workshops on undergrounding of power lines, our customers raised specific concerns regarding the risks that our power lines present at high traffic intersections and roads. In response, SA Power Networks is proposing a targeted approach to undergrounding power lines at locations that have repeatedly been impacted. The proposed forecast expenditure for this program is $77.4 million (June 15 $). This expenditure is supported by our detailed Willingness to Pay analysis, refer to Attachment 6.8.

To ensure prudency of the program, a working group consisting of SA Power Networks, Motor Accident Commission (**MAC**) and Department of Planning, Transport and Infrastructure SA (**DPTI**) personnel has been formed to guide the location of the proposed investment. An initial assessment has identified two sites for remediation, with a further eight sites to be identified and remediated in the 2015–20 RCP.

SA Power Networks is proposing a level of expenditure of $77.4 million (June 15 $). This is $30.3 million below the level supported by customer's Willingness to Pay responses. We have reduced the proposed expenditure after giving consideration to the overall capital expenditure program and the related impact on customers bills, refer to our Undergrounding for Road Safety business case (Attachment 20.46).

20.6.6 Network Other

This section should be read in conjunction with Chapter 15 'Fitting in with our streets and communities'.

Network Other expenditure comprises of the Power Line Environment Committee (**PLEC**) program associated with the undergrounding of selected parts of the network in accordance with State Government Legislation and the PLEC Charter.

The PLEC program is an undergrounding program to improve the aesthetics of electricity infrastructure to benefit the community, having regard to road safety and electrical safety. SA Power Networks is responsible for undertaking an annual PLEC program as defined in Part 3A of the *Electricity (General) Regulations 2012*. We must comply with this applicable regulatory obligation (NER 6.5.7(a)(2)).

The PLEC program is an 'un-scoped allowance' in accordance with the Regulations. The program can be considered prudent as it is managed within a legislated framework and the program can be seen as efficient as construction is predominantly completed via a competitive tender process.

The Network Other forecast expenditure in the current RCP is $40.9 ($ million, nominal), $1.6 million above the AER allowance of $39.3 ($ million, nominal), refer Table 20.36. The Network Other capital expenditure for the current period is in line with the AER allowance.

SA Power Networks' Network Other forecast expenditure for the 2015–20 RCP is summarised in Table 20.37. The increase in expenditure represents a CPI increase in accordance with the formula outlined in the *Electricity Act 1996*.

Table 20.36: Comparison of network other AER allowance and actual/forecast capital expenditure ($ million, nominal)

Network Other expenditure	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Allowance	7.5	7.7	7.8	8.1	8.2	**39.3**
Actual/forecast	8.0	7.4	8.2	8.2	9.2	**40.9**

Table 20.37: SA Power Networks' network other capital expenditure for 2015–20 (June 2015, $ million)

Network other expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Forecast	9.0	9.1	9.2	9.4	9.5	**46.3**

20.7

Connections and customer driven works

This section explains why our forecast capital expenditure for connections and customer driven works is required in order to achieve the capital expenditure objectives and how that forecast expenditure reasonably reflects the capital expenditure criteria and takes into account relevant capital expenditure factors. This section should be read in conjunction with Chapter 12 and the referenced attachments to gain a full appreciation of our Proposal.

Customer connection expenditure is associated with additions, upgrades or alterations resulting from the requirements of specific customers supply requirements. This expenditure is divided into a number of categories, being:

- **Minor Customer Connections** (less than $30,000) — connections generally associated with new houses or small business or additions and alterations to existing houses or small businesses;
- **Medium Customer Connections** (between $30,000 and $100,000) — connections (typically consuming more than 100 Amperes, 3-phase supply in urban area and more than 25kVA in rural area), generally associated with non-residential buildings, eg businesses and 'other' dwellings (ie flats);
- **Major Customer Connections** (more than $100,000) — connections generally associated with large business investment, eg defence, mining, major non-residential buildings, shopping centres and intensive agriculture, and government and private infrastructure investment, ie schools, railways and water supply; and
- **Underground Residential Developments** — real estate development connections to the existing distribution network of new housing developments.

A new framework has been established across the National Electricity Market (**NEM**) known as the National Energy Customer Framework (**NECF**). Prior to the NECF, each state, including South Australia, had its own jurisdictional arrangements.

SA Power Networks partially adopted the NECF on 1 February 2013, with the intention of full adoption from 1 July 2015 with the inclusion of the NECF connection charging obligations. The NECF applies to all SA Power Networks customers who apply for a connection service. It provides provisions for:

- the retailer-customer relationship and associated rights, obligations and consumer protection measures;
- distributor interactions with customers and retailers, and associated rights, obligations and consumer protection measures;
- retailer authorisations; and
- compliance monitoring and reporting, enforcement and performance reporting.

20.7.1
Connection Policy

Pursuant to Chapter 6 of the NER, SA Power Networks must prepare a Connection Policy, "setting out the circumstances in which it may require a retail customer or real estate developer to pay a connection charge, for the provision of a connection service under Chapter 5A."

The Connection Policy must specify a range of matters, covering:

- the categories of customers that may be required to pay a connection charge;
- the circumstances in which such a requirement may be imposed;
- the aspects of a connection service for which a connection charge may be made;
- the basis on which connection charges are determined;
- the manner in which connection charges are to be paid (or equivalent consideration is to be given); and
- a threshold below which a customer will not be liable for a connection charge for an augmentation other than an extension.

SA Power Networks has prepared a proposed Connection Policy to cover connection services provided over the 2015–20 RCP (1 July 2015 to 30 June 2020) (refer Attachment 12.1).

The approval of this Policy by the AER is a constituent decision of the AER's Determination for the 2015–20 RCP, and consequently, remains in force for the entirety of the period.

20.7.2
Current period outcomes

The actual and forecast customer connections net expenditure compared to the AER allowance for the 2010–15 RCP is shown in Table 20.38. The gross connections forecast expenditure for the current RCP is $609.1 ($ million, nominal), $169.4 million below the AER allowance of $778.5 ($ million, nominal).

The connections forecast contributions for the current RCP is $455.6 ($ million, nominal), $156.0 million below the AER allowance of $611.6 ($ million, nominal), refer to Table 20.39.

As the current period progressed there was a general downturn in customer connections as a result of a slowing South Australian economy. This impacted many sectors of customer connections including real estate developments, residential housing construction, manufacturing and mining.

The downturn was slightly off-set by other sectors including government projects, support services (eg HR, IT, Finance), food production, and retail sales industries which remained steady and by the Government incentivised solar panel installations which drove a significant rise in associated alteration activity during the period.

The connections forecast for the current RCP was based on BIS Shrapnel's (**BIS**) economic outlook for South Australia which was accepted by the AER. At the time of submission the downturn in customer connections was unforeseen.

In the latter part of this period (2010–15), we are experiencing a gradual return to historic customer connection expenditure levels.

20.7.3
Forecast methodology

SA Power Networks has engaged BIS to prepare a forecast of its customer connection expenditure from 2014/15 to 2019/20. This report is included as Attachment 12.5.

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 (discussed above), SA Power Networks has calculated the proportion of the customer contribution to the connection costs on the basis of the new Connection Policy (2015/16 to 2019/20 period). This aligns with our historical contribution and connections ratio.

The unit costs for each category are applied as constant by virtue of the methodology utilised by BIS in their forecast. It should be noted that the vast majority of these works are contestable (work that can be built in isolation to the existing distribution network and is performed by appropriately accredited design and construction resources) up to the connection point under SA Power Networks' framework. Competitive pressures can therefore be relied upon to drive efficient costs.

BIS developed the customer connections expenditure forecast for the 2015–20 RCP using the forecasting methodologies described below. SA Power Networks developed the forecast contributions in accordance with our Connections Management Plan AMP 7.1.01.

Table 20.38: Comparison of gross connections expenditure AER allowance to actual/forecast capital connection expenditure ($ million, nominal)

Connections	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Allowance	156.7	156.6	145.8	157.1	162.2	**778.5**
Actual and forecast	132.3	126.5	110.1	116.8	123.4	**609.1**

Table 20.39: Comparison of connections contributions AER allowance and actual/forecast received connection contributions ($ million, nominal)

Contributions	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Allowance	(124.4)	(123.6)	(113.7)	(122.4)	(127.5)	**(611.6)**
Actual and forecast	(109.7)	(91.2)	(71.9)	(84.8)	(97.9)	**(455.6)**

Minor (<$30,000)
The minor connections expenditure model uses various economic drivers and historical data from ABS as follows:

- total residential connection expenditure is assumed to be driven primarily by forecasts of residential building alterations and additions approval activity for South Australia;
- small commercial connection activity (accounts for approximately 1% of total minor customer connections expenditure) is assumed to be driven by the real value of non-residential commencements for buildings with an individual value below $1 million; and
- URD connections expenditure model is assumed to be driven by total house commencements.

Underpinning the forecasts of residential building and non-residential building activity is BIS forecasts of South Australian population growth.

SA Power Networks developed the contributions for minor connections based on historical contribution levels of 49% of expenditure.

Medium Customer Connections (Projects $30,000 to $100,000)
The medium connections expenditure model is based on historical data from SA Power Networks, ABS and on forecasts of the following drivers:

- the real value of non-residential building commencements for projects below $20 million; and
- the number of 'other' dwelling commencements, in particular, flats (ABS Building Activity Catalogue No. 8752.0).

These two drivers are weighted because it was found that changes in the value of non-residential building commencements had a greater impact on medium customer connections expenditure than changes in the commencement of flats.

SA Power Networks developed the contributions for medium connections based on historical contribution levels of 64% of expenditure.

Major Customer Connections (Projects >$100,000)
The forecasts for major connections expenditure were developed from a bottom-up process, as follows:

- SA Power Networks' forecasts of major project developments were reconciled with BIS list of major projects in the infrastructure (engineering construction) and non-residential building sectors. This was used to produce a list of possible major connection projects, covering their starting dates, load (ie kVA), estimated connection cost, and likelihood of proceeding;
- any project below a 50% likelihood of proceeding was removed, but the timing, probability and value of removed projects were noted and taken into consideration; and
- the estimate connection cost of each included major project was summed to arrive at a grand total.

A residual for unknown and possible customer driven projects has been included in the forecasts. This residual was derived from the forecasts for non-dwelling building commencements (projects above $20 million) and engineering construction activity (excluding sectors not deemed relevant) and review of historical actual expenditure for this category.

SA Power Networks developed the contributions for major connections based on historical contribution and forecast impact of the NECF Connection Charge Guidelines and determined contribution levels of 60% of expenditure.

Underground Residential Developments (URDs)
The URD forecast is based on the residential forecast as per Minor Connections, as URDs lead new housing commencements. Additionally SA Power Networks reviews its forecasts of known URD's and allowances for residual projects where reconciled with BIS forecast.

SA Power Networks developed the contributions for URDs based on historical contribution and forecast impact of the NECF Connection Charge Guidelines.

20.7.4
Forecast annual expenditure

SA Power Networks' forecast connection expenditure (gross and net) and contributions for the 2015–20 RCP has been developed based on the full adoption of new NECF obligations (inclusive of Connection Charge Guidelines; under Chapter 5A of the National Electricity Rules). The forecast customer connection expenditure, contributions and connections net, for the 2015–20 RCP are shown in Table 20.40.

BIS' outlook for customer works for the 2015–20 RCP is discussed below.

Minor (<$30,000) and URDs

Minor customer connections are made up of alterations to existing supplies and connection of new supplies for predominantly residential customers. Minor customer projects are split between alterations and new connections.

After a decline in total dwelling commencements in recent years, strong growth is estimated to have re-emerged in 2013/14 and is forecast to continue into 2014/15. Rising borrowing costs and prices into 2015/16 and 2016/17 and then subsequently weaker economic conditions into 2017/18 are expected to drag on new housing construction over the longer term. As economic conditions rebalance and the domestic economy moves back into an upturn phase, dwelling investment is forecast to lift moderately off a low base over the following two years to 2019/20.

Overall, total dwelling commencements in the longer term are forecast to be consistent with the previous five years to 2012/13.

Alterations and additions activity tends to track movement in new dwelling construction, although with less amplitude. As such, alterations and additions are expected to hold relatively flat over the forecast horizon.

Medium Customer Connections (Projects $30,000 to $100,000)

Medium customer connections are made up of small to medium commercial and residential connection works. The major trends and drivers associated with medium customer projects include:

- non-dwelling building commencements in the small to medium range; and
- flats commencements.

Non-dwelling building construction has experienced larger, but less frequent, cyclical fluctuations than dwelling construction. This is because of the long gestation period between the planning and construction of non-dwelling building, and uncertainty in estimating demand, rentals and prices, which makes this sector more prone to oversupply (and undersupply).

Although economic conditions are forecast to improve modestly over the next few years, there is enough slack in the Adelaide office and accommodation market at present to prevent any major improvement in commercial building over the next five years. Public investment in new building works is expected to be constrained, as both the federal and state governments tighten capital allocations given their tight fiscal positions. These factors should see a relatively flat profile for non-residential building over the next five years.

Flats commencements lifted sizably in 2012/13, assisted by low interest rates, first home owner grants and off-the-plan stamp duty concessions for new apartment purchases. However, flat commencements are expected to ease off this high base over the coming years, as incentives are wound back and interest rates begin to gradually lift into 2016.

Overall, flat building commencements in the longer term are forecast to average marginally more than the previous five years.

Major Customer Connections (Projects >$100,000)

Major customer connections are made up of connection works for major non-residential buildings, industrial projects, government and private sector infrastructure projects, large residential land developments and the occasional multi-unit residential or retirement village project. In South Australia, value of major projects tends to be the key driver of activity, rather than changes in project volumes.

The major trends and drivers associated with major customer projects include:

- Major non-dwelling building commencements (projects above $20 million); and
- Major engineering construction commencements, including infrastructure such as roads, bridges, railways, harbours, water supply, sewerage works, electricity generation and supply works, and heavy industry construction.

A moderate lift on major customer works is estimated for 2013/14 and forecast to continue for 2014/15 as gradually improving economic conditions and some sizable projects like the $175 million Skycity Casino Redevelopment provide a boost. A lack of major new projects is predicted to result in a weaker outcome for 2015/16, before sustained growth re-emerges towards the end of the forecast horizon. An upturn in commercial building (offices especially) underpins much of the rise towards the end of the decade.

Table 20.40: SA Power Networks' actual and forecast connections expenditure (gross and net) and contributions for the 2015–20 RCP (June 2015, $ million)

Customer connections expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Connections	136.0	138.3	140.8	147.6	155.1	**718.0**
Contributions	(102.0)	(102.1)	(103.6)	(108.0)	(112.8)	**(528.5)**
Net expenditure	34.0	36.3	37.2	39.7	42.3	**189.4**

20.8

Non-network expenditure

In Chapter 16, we have comprehensively outlined the significant enhancement required to our business capabilities. As a progressive organisation, SA Power Networks will continue to build and develop our capabilities to ensure we can deliver on all our regulatory obligations and meet our customers' expectations.

The 2015–20 RCP will be a period that will see the most significant and transformative change in the distribution sector since the establishment of the NEM. These changes include:

- **Technology** — digital technologies continue to proliferate in all areas of our industry and society, data volumes are rising exponentially, convergence and integration of technologies, systems and processes are accelerating, legacy systems that are unable to provide required flexibility;
- **Consumer** — everyday usage of mobile technologies is changing expectations of service providers, information access is now regarded as essential, interest in and adoption of new distributed energy resources is now mainstream, choice in energy options to help manage costs and convenience is increasingly expected;
- **Market** — new sectors have emerged around micro-generation, energy usage and demand patterns have transformed, new markets for electrical products like electric vehicles and storage are emerging, new competitive sectors are emerging (eg metering, home energy systems and energy services);
- **Regulatory** — governments are highly active in energy policy and incentive systems, regulators are pursuing competition outcomes in previous monopoly sectors, and are demanding new data requirements of monopoly sectors for oversight and benchmarking purposes; and
- **Workforce** — ageing employees will soon retire, transfer of skills to new employees is critical, new skills to support emerging service requirements are needed, and the challenge of attracting, retaining and motivating employees is growing.

In this context, our areas of focus on developing our business capabilities to enable delivery of services over the coming RCP include:

- a continuing focus on providing the right services;
- optimal integration of technologies and systems;
- an integrated approach to Business Improvement;
- an effective workforce strategy; and
- fit-for-purpose facilities and equipment.

In this section, the non-network sub-categories of IT, Communications, Buildings and property, Vehicles, and Other are detailed.

For each sub-category, we examine the 2010–15 RCP capital expenditure outcomes, the expenditure forecasting approach for the 2015–20 RCP, the expenditure forecast for the 2015–20 RCP and reasoning underpinning the expenditure forecast.

20.8.1
Information Technology

Information Technology (**IT**) expenditure is associated with maintaining IT systems and delivering new capabilities required to support SA Power Networks' operations and business. Network information technology costs are included in the Network expenditure sections.

2010–15 RCP expenditure and performance outcomes for IT

The IT actual/forecast expenditure for the current RCP is $153 million ($ nominal) which is above the AER allowance of $147 million ($ nominal), refer Table 20.41.

Prior to 2010, SA Power Networks' IT department was primarily focused on establishing the major business systems that underpin the SA Power Networks business today.

During the 2010–15 RCP, the focus moved to technology refresh and incremental enhancements to the IT capabilities established in previous periods. In practice, faster than expected changes in the business environment triggered key organisational changes and imposed greater than expected reliance on IT capabilities. Additional investments were required in the works management, asset management, customer facing and regulatory systems due to changed customer expectations, regulatory obligations and increased business demand.

Our rapid IT growth based on business demand for additional capabilities resulted in a number of new bespoke standalone applications being developed in order to support the immediate needs of the business. The increased complexity of the IT environment drove a significant uplift in support and maintenance costs and has consequently resulted in increased risk and a less than optimal maintenance and upgrade regime.

Table 20.41: Comparison of Information Technology AER allowance and actual/forecast capital expenditure ($ million, nominal)

Non-network Information Technology	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Allowance	27.9	24.5	21.5	27.5	45.4	**146.8**
Actual/forecast	20.6	26.6	25.6	27.6	52.9	**153.4**

Changes to the original strategy for 2010–15 were managed via appropriate governance processes in accordance with SA Power Networks' capital expenditure policies and procedures.

As part of the governance processes we worked with our Victorian counterparts, CitiPower and Powercor, to extend the life of our billing system, CIS OV, through negotiations with the vendor and a series of technical upgrades. The CIS OV system is 15 years old and is a legacy system. Through prudent management over the past six years SA Power Networks has been able to defer the replacement until a more appropriate time for both organisations to embark on the significant technology program. Some immediate responses to customer preferences in South Australia regarding National Energy Customer Framework (**NECF**) and customer facing applications received priority. The change to the core customer system is to be undertaken in the 2015–20 RCP, and will address the risk of the current system, emerging technologies and heightened customer and regulatory expectations that now need to be factored in as additional business requirements.

The prudent deferral of the CIS OV replacement afforded the opportunity to redirect the focus on IT developments to support business requirements, such as:

- compliance with the NECF;
- provision of more timely service and up to date outage-related information to customers such as:
  - Faulty Street Light reporting (online); and
  - Power@MyPlace; and
- commencement of key strategic initiatives identified as foundations for further capability required in the upcoming RCP. These projects delivered important foundational components into the business which will be further leveraged during 2015–20 including:
  - enterprise project management framework, methods, templates and portal;
  - improved collection, management and reporting of vegetation management information;
  - improved fleet management capability (system enhancements);
  - commencement of design management tool consolidation;
  - asset management priority asset tool (stand alone IT system); and
  - single estimating tool.

2015–20 RCP expenditure forecasting approach for IT

What has become clear is that we need to move away from the incremental change to business processes (which has occurred over many years) to a more integrated 'end state' approach to data, systems, processes and people which is linked to service outcomes and business objectives. Our business processes are spread across multiple IT systems creating hurdles to delivering business requirements and responding to customer needs.

Importantly:

- it is now imperative that we invest in the business systems to establish a strong and enduring linkage of data relating to assets, customers and work to:
  - deliver the excellence in asset management (managing an ageing and deteriorating network infrastructure which now needs to cater to two-way energy flows);
  - enable the delivery of the services that customers are expecting now and in the future; and
  - support the ongoing prudent and efficient operation of our business;
- without the proposed investment in people, data, systems and processes we will not be able to satisfactorily meet the challenges of the changing environment and provide the expected outcomes to our customers and our owners in the most cost-efficient way;
- by embracing the opportunities from digital technologies over the next few years SA Power Networks will be well placed for the long term. Without this investment there is a risk that services provided to customers will be below expectations and lag developments in other industries and across Australia;
- the skills, maturity and loyalty of our employees have been and will remain a foundation for our business success. To continue to benefit we need to invest in enhancing their skills to deal with new technologies and to provide them with the right tools, facilities and vehicles; and
- rapidly changing technology and increase growth in data volumes means significant change to our business.

The investment in network infrastructure and customer facing developments (outlined in earlier sections) combined with the significant changes to people, data, systems and processes warrants an integrated approach to business improvement. Accordingly, we have established a framework and associated organisational arrangements to ensure the effective management of these changes and to enable Executive Management oversight commensurate with our governance framework. To this end we:

- have developed an enterprise architecture aligned to industry standards and good business practice which provides the enterprise road map for our preferred 'end state';
- have established Corporate Portfolio Management and Enterprise Architecture groups to facilitate the management of all change initiatives and to ensure they are aligned with our end state and that they are delivered as expected; and
- are progressively implementing a corporate wide approach to quality and continuous improvement which will consolidate the variety of approaches to quality currently operating in SA Power Networks.

The IT forecasts for the 2015–20 RCP have been developed by the business and approved by the Chief Information Officer (**CIO**). Forecasts are based on business requirements identified during the capital planning process in accordance with SA Power Networks' capital expenditure policies and procedures (refer to Attachment 20.35 IT Strategy 2014–2020 and Attachment 20.32 IT Investment Plan 2015–2020).

The requirements are grouped into two distinct segments;

- **Recurrent expenditure** — the 'base' level of expenditure necessary to keep the existing IT systems and infrastructure operational during the 2015–20 RCP assuming the current level of IT services and a prudent cycle of software and infrastructure upgrades and also includes client devices; and
- **Non-recurrent expenditure** — the expenditure needed to respond to the business requirements (business change projects) identified for the 2015–20 RCP, which are in turn influenced by internal, external and technology drivers including risk mitigation, regulatory changes, customer preferences and emerging technology trends.

For those requirements with alignment to business strategies and the NER objectives, business cases have been developed to ensure the investment is prudent and that the most efficient option is selected when taking into account of the overall strategy of having an integrated suite of functionality. Business cases contain detailed cost estimates, cost-benefit analysis, options analysis and the justification for the preferred option based on the AER's Expenditure Forecasting Assessment Guideline. Business cases are approved by key business stakeholders and senior management following a governance process aligned with the standard SA Power Networks' capital expenditure evaluation procedures.

Additionally, portfolio analysis has been undertaken to identify critical dependencies and enabling capabilities required to be implemented in order to deliver the most efficient outcomes for the organisation (refer to Figure 20.34).

Due to the amount of business change being undertaken by the portfolio of work, business costs covering activities such as change management and business process changes associated with implementing projects listed in this section, have been costed separately. Although these are part of the total cost of ownership of projects and are included in the individual business cases, the expenditures are covered in Section 20.8.5 — Non-Network Other. The business change costs is to cover extra labour resources required within our business units to ensure the IT capability changes are managed and embedded, effectively and efficiently.

Outcomes derived from the portfolio of work have forecast benefits of $21.2 million (June 15 $) (being cost reduction within the RCP) to be realised across the entire business from the portfolio investment. The portfolio investment will also generate $36.8 million (June 15 $) of avoided costs, that is, additional expenditure (predominantly labour) that would be required to meet legal, regulatory, customer and business requirements if systems are not developed and implemented. The required additional operational expenditure to support ongoing maintenance and support of the new capabilities from the portfolio has been offset by the benefits being realised in the RCP (see Section 21.6.2 for the opex impact and also Attachment 20.42 for the Benefits Map).

For further detail on each individual initiative see Attachment 20.28 for the list of Business Cases.

Figure 20.34: Portfolio view of non-recurrent projects including milestones and dependencies
NOTE: A LARGER VERSION OF THIS CHART CAN BE FOUND IN ATTACHMENT 20.29

All detailed cost estimates have utilised standard estimation templates and methods. An over arching IT forecasting model is utilised to produce final cost estimates with the following main sources of information used as inputs:

- project information templates are completed for all capital projects. The lists of projects include both the projects that form part of the business cases and other recurrent capital projects. The project information templates provide detailed breakdowns of human and material resources by calendar year and capital/operational category. Human resources are specified in terms of the individual roles and the estimated value of their effort in days per annum;
- system information templates are completed for all major systems. The system information templates capture the estimated future labour and services costs required for operational system maintenance;
- service information templates are completed for the key services and capture the estimated future labour and services costs required for ongoing provision of the services; and
- licence costs are based on the 2013–14 system licence costs included in the IT budget.

Data is then consolidated from the multiple sources into a single forecast (see Figure 20.35).

Figure 20.35 outlines the IT expenditure modelling process.

Expenditure forecast for the 2015–20 RCP for IT

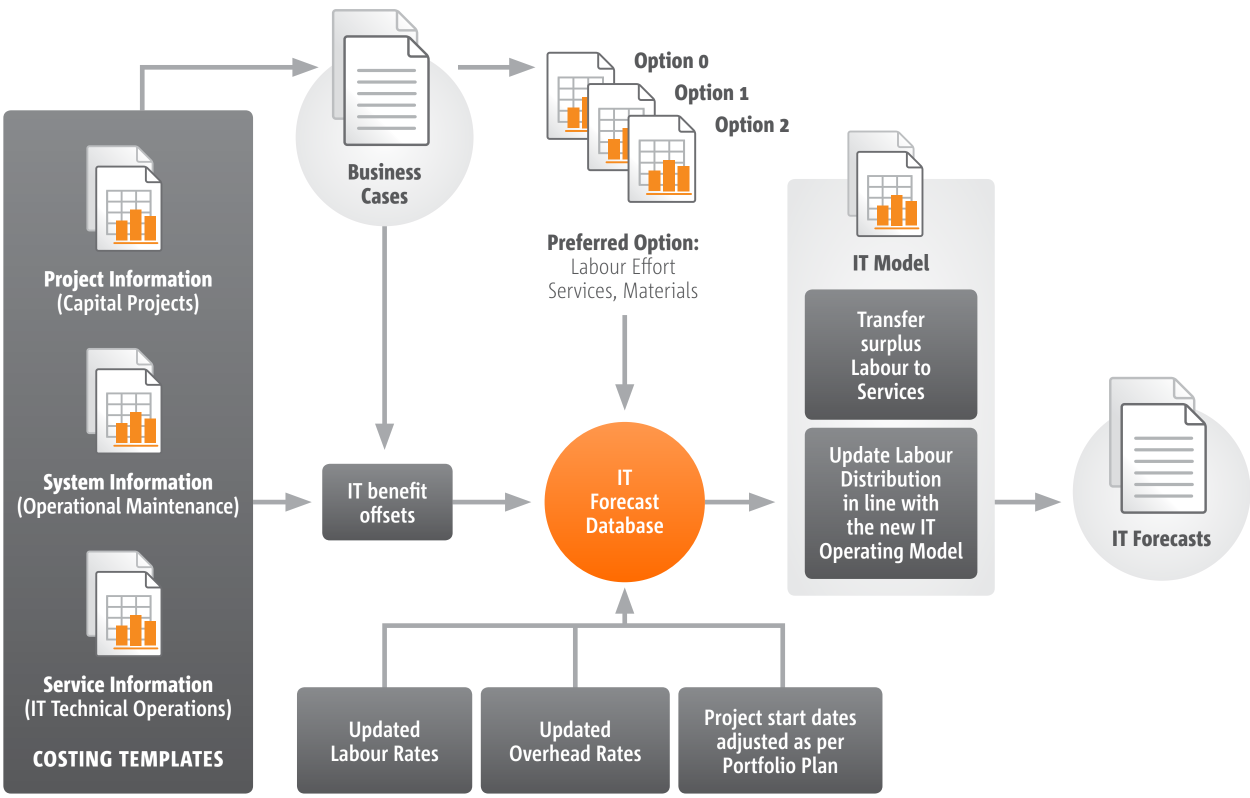
Forecast IT capital expenditure for the 2015–20 RCP is shown in Table 20.42, which represents an increase from the 2010–15 RCP.

The increase associated with the recurrent program of work is due to the following key factors;

- increased support requirements for key applications and infrastructure owing to the management of the enlarged applications environment;
- strengthened demand for systems reliability, IT support and user training arising from the increased reliance on IT based information and systems;
- an increase use of mobile computing across the organisation;
- the level of required software upgrades and equipment renewals in line with supplier recommendations, reflecting the upgrade requirements of the additional hardware and applications installed during the current RCP; and
- compounding effects of the introduction of new business systems and capabilities on the IT support requirements, including additional data storage, network capacity, disaster recovery and integration with the existing systems.

The areas of recurrent spend are listed in Table 20.43.

Figure 20.35: IT expenditure forecast modelling process



SOURCE: SA POWER NETWORKS

Table 20.42: IT forecast expenditure for the 2015–20 RCP (June 2015, $ million)

IT Expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
IT Recurrent expenditure	26.7	25.2	24.4	24.0	25.7	**126.0**
IT Non-Recurrent 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**

*Business change expenditure is covered in Section 20.8.5, figures are shown here for completeness

Table 20.43: IT recurrent expenditure (June 2015, $ million)

Recurrent Initiatives 2015–20	$m
Client devices	19.7
Technical operations	25.0
Applications	43.5
National market systems	11.0
Business system upgrades	21.0
Management, risk, compliance and governance of IT	5.6
Business costs	0.2
Total	**126.0**

The increase associated with the non-recurrent program of work is to support the business delivering outcomes for customers and owners as follows:

- new technology requirements to meet the changes in the external environment (eg changes in the consumer preferences, regulatory changes, environment changes, technology changes) and the internal SA Power Networks environment (eg changes in the business operating model). Key focus areas include:
  - improved SA Power Networks asset management capability required to ensure long-term sustainable performance and condition of the assets. The associated IT improved visualisation capability of spatial asset data;
  - increased expectations of SA Power Networks customers regarding levels of service and quality of information. The IT implications include improved customer data management capabilities and the provision of customer self-service reporting options;
  - progressive rollout of smart ready and other demand-side participation technologies which require increase data storage, processing and analysis capabilities;
  - building new capabilities for our workforce to deliver on additional data requirements, customer expectations and increased work program;
  - increased level of cyber security threats that require greater investments in the IT security systems and processes to ensure corporate and operational systems and information are protected in an event of an attack; and
  - implementing enterprise enabling technologies to support new capabilities;
- changes to the IT operating model required to support the increased volume of capital work; and
- managing the risk of our older core systems such as CIS OV and our Enterprise Resource Planning system (**ERP**).

Core systems

Upgrading or replacing our core systems substantially reduces risk and offers opportunities to enable future capabilities cost effectively. New versions and products available have extended capabilities to meet our future requirements.

This allows us to gain current functionality required to maintain our business but also allows for growth and to enable new functionality when the business requires it in future years. Instead of our replacement program only implementing 'like for like' products, we will ensure we consider future requirements and solutions that offer flexible capabilities. This will minimise costs of adding new modules or extra products at a later date.

Implementation risk is reduced and performance increased as systems are not being changed multiple times. The cost avoidance and efficiency benefits of new capability can be achieved earlier. Hence our system replacements and refreshes are functionally 'like for like' but also include enabling the extended and new capabilities that the enterprise will require be rolled out over the coming years.

For instance, our ERP was first implemented almost 20 years ago and has gradually been expanded in its use to meet organisational requirements. However the system (designed and built almost two decades ago) is struggling to cope with the current demands and will certainly not meet the business requirements of the next 5–15 years.

These issues have become more apparent in recent years as greater requirements for condition based asset management, improved work management, mobility capabilities and greater regulatory reporting requirements (including RIN) have consistently exposed underlying system and data structure issues and in some instances, meant the implementation of short term 'tactical' solutions because the existing SAP architecture was not able to deliver at the time to the requirements.

External reviews of the system indicated that the most prudent path was a substantial refresh of the SAP. This is fundamentally a ground up redesign of the system to take advantage of the existing investment but prepare it for the current and future requirements, refer Attachment 20.40.

This refresh commenced in 2014 with initial steps including hardware replacements, system upgrades and the organisational structure. It will continue into the 2015–20 RCP with a particular focus on ensuring a strong and reliable platform for the long term management of assets, work and enabling the complete view of an asset. Leveraging the strengthened SAP provides the technology foundation for the enterprise 'end to end' business process capabilities and for our approach to systems consolidation.

Detailed initiatives to support the key factors are listed in Table 20.44 and supporting business cases for each of these initiatives are listed in Attachment 20.28.

Table 20.44: IT non-recurrent initiatives (June 2015, $ million)

Non-recurrent Initiatives 2015–20	Description	IT $m	Business change activities $m	Total $m
Intelligent design management system	Consolidate design tools and implement a standardised design tool	7.9	1.3	**9.2**
Enterprise asset management	Enhance and upgrade capabilities into an integrated enterprise approach to asset management including improvements in vegetation management	14.1	17.3	**31.4**
Portfolio project management (PPM)	Enterprise wide tool to view and manage all components of portfolios, programs and projects (ie scheduling, resource planning)	3.1	0.9	**4.0**
Financial management	Upgrade current financial management systems for compliance and capabilities (ie existing General Ledger, Fixed Asset register)	5.1	2.8	**7.9**
People and culture improvements (HR)	Single view of employees and organisational structure and additional capabilities required for managing employees and skills	1.4	0.7	**2.1**
RIN reporting	Update and implement new systems, processes and data to meet the AER RIN requirements reporting	3.9	11.1	**15.0**
CIS OV and CRM	Replace legacy billing and legacy customer related systems with a modern flexible billing engine and associated single view of customer system	54.3	4.1	**58.4**
Customer facing technologies	Improve communication channels and information to customers	8.3	-	**8.3**
Customer call management replacement	Replace legacy call management system	0.8	-	**0.8**
Tariff and metering	IT costs associated with the introduction of cost reflective tariffs and advanced metering	22.7	4.3	**27.0**

Table 20.44: IT non-recurrent initiatives (June 2015, $ million) continued

Non-recurrent Initiatives 2015–20	Description	IT $m	Business change activities $m	Total $m
Field force mobility	Significantly enhance existing field mobility capabilities	6.8	1.9	**8.7**
Supply chain	Enable the visibility and management of inventory across depots and warehouses. Extend our data analytics and supplier management capabilities	3.3	0.9	**4.2**
Enterprise mobility	Implement a cohesive, secure and standard IT platform for mobility	2.4	-	**2.4**
Enterprise information security	Foundation enterprise security control capabilities	7.1	-	**7.1**
IT management and operations	Implement good practice IT management capabilities (ie Application Lifecycle, Configuration)	6.5	0.1	**6.6**
Governance, risk, regulation and compliance	Upgrade to an enterprise wide, integrated solution to manage governance, risk and compliance processes	1.7	0.1	**1.8**
Enterprise integration	Implement technical foundations for enterprise integration platforms for data and systems	6.6	-	**6.6**
Data centre consolidation	Rationalisation of data centres, increase good practice disaster recovery and governance practices	4.3	-	**4.3**
SAP foundations	Upgrade SAP hardware platform (incl Oracle database systems and User Interface for ERP system)	6.2	-	**6.2**
Business intelligence enablement	Foundational technical components to enable robust business, customer and regulatory reporting including data, analytics and information management	2.6	-	**2.6**
Data management	Implement a standard foundation Data Management toolset (ie Enterprise, Quality, Lifecycle)	2.6	0.1	**2.7**
Enterprise information management	Implement a standard foundation to enable efficient management of documents, records and web content	7.4	-	**7.4**
Unified communications	Upgrade telephony and business communications system and implement new integrated communications channels	1.9	-	**1.9**
Enterprise architecture	Enterprise Architecture repository based toolset	0.9	-	**0.9**
Total		**181.9**	**45.8**	**227.5**

SA Power Networks engaged KPMG to independently assess its methodology and approach to developing the information technology capital and operating expenditure forecasting for the 2015-20 RCP. As part of the report, a comprehensive analysis was performed against the NER objectives, criteria and factors. The detailed finding of their analysis is provided in Attachment 20.31. The report specifically comments on the investment context, governance, forecasting methodology, and IT forecasts. The report provides significant commentary on the investment drivers, benchmarking analysis, and examination of specific business cases.

In addition, according to Huegin's benchmarking analysis (see Section 4.2), SA Power Networks' Information, Technology and Communications (**ITC**) total expenditure is consistently lower than most other DNSPs. This indicates SA Power Networks' relative efficiency and also a level of minimal investment in ITC compared to industry peers (refer Figure 20.36).

In conclusion, SA Power Networks has had a history of low IT spend, and fit for purpose, point to point solutions. As the industry matures and stakeholder needs change, we need to adapt to deliver on the increased volumes of data and complex information requirements.

Our current systems, although suitable when built, are now no longer able to support our future state. Investing in end to end processes and systems, and build our foundational IT infrastructure and data support mechanisms, will enable SA Power Networks to:

- support outcomes from Power of Choice efficiently;
- be compliant to regulatory requirements;
- continue to maintain our levels of service; and
- respond effectively to our customers' growing expectations.

20.8.2 Communications

Non-network communications expenditure is required to enable day to day operation of our distribution network and telecommunications network.

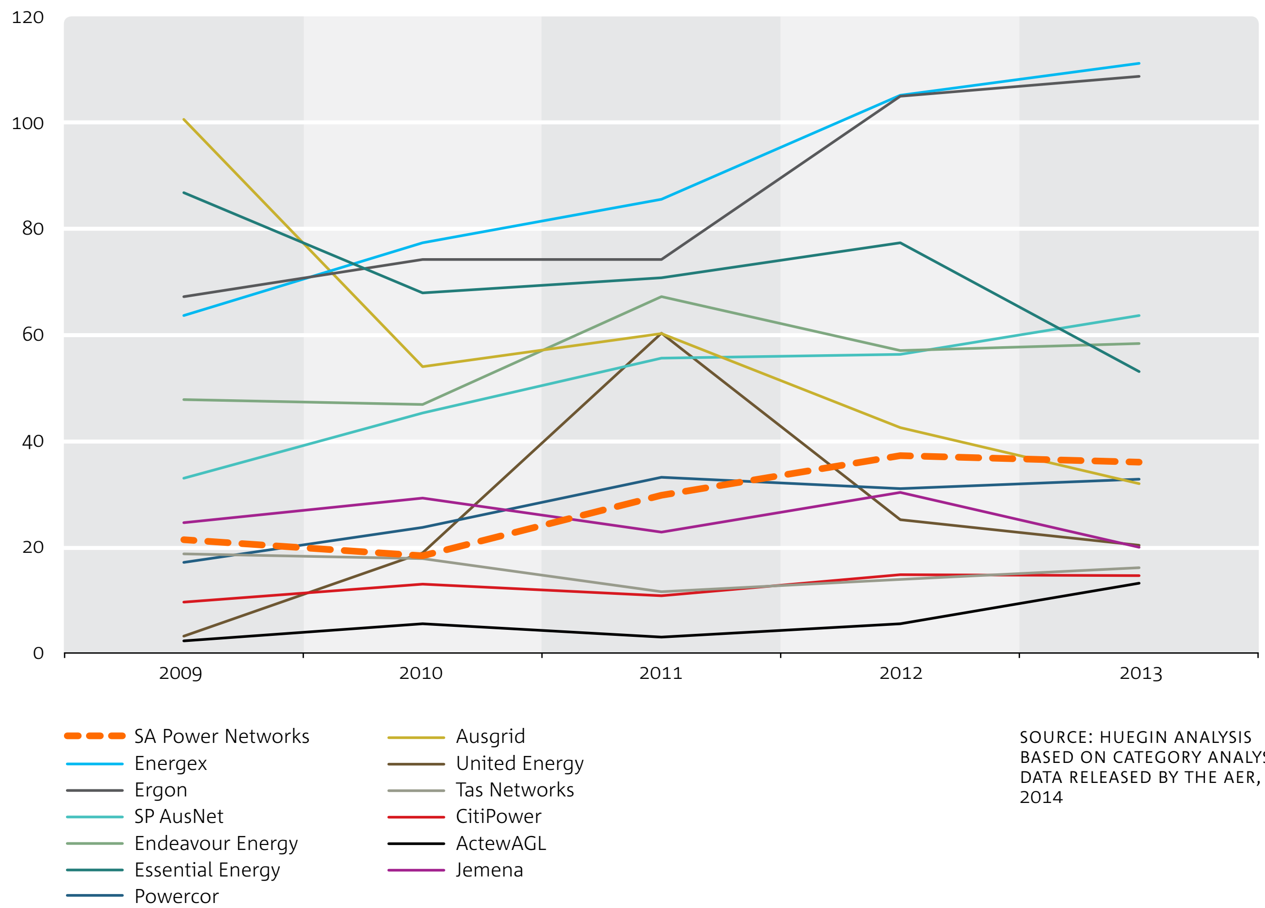
The current period expenditure for non-network communications is included within the strategic network expenditure category, refer Section 20.6.3.

2010–15 RCP expenditure and performance outcomes for communications

In the current period the following non-network communications projects have been undertaken:

- expansion of our Network Control Centre (**NOC**) and commissioning of an off site back up NOC; and
- implementation of the first stage of our Advanced Distribution Management System (**ADMS**) in our NOC.

Figure 20.36: IT total expenditure ($ million, nominal)



SOURCE: HUEGIN ANALYSIS BASED ON CATEGORY ANALYSIS DATA RELEASED BY THE AER, 2014

Expenditure forecast for the 2015–20 RCP — communications

SA Power Networks' non-network communications forecast expenditure for the 2015–20 RCP is $25.5 million (June 2015) and is summarised in Table 20.45.

Table 20.46 provides details of our non-network communications program for the 2015–20 RCP.

20.8.3 Buildings and property

We own and lease a range of properties across the State, including a mix of office and depot accommodation. Buildings and Property expenditure relates to the acquisition, maintenance, refurbishment and disposal of our commercial, industrial and metropolitan and country depots. Substation property and line easement expenditure forecasts are incorporated separately within the Network cost categories.

The current profile and composition of our property portfolio is shown in Table 20.47.

Table 20.45: SA Power Networks' non-network communications capital expenditure for 2015–20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Forecast	11.5	8.1	4.0	1.7	0.3	**25.5**

Table 20.46: Non-network communications program for the 2015–20 RCP

Communications	Description	AMP
Network Operations Centre	Final stage of implementation of our ADMS system	2.1.02
Telecommunications Network Operations Centre	A once off expenditure to accommodate the expanded TNOC and the implementation of a number of systems to manage the revised operating environment	3.3.08
Government Radio Network	A one time payment to Government Radio Network (**GRN**), for a capacity increase on their network to accommodate the transition of SA Power Networks' emergency switching communications (mobile radio) to the GRN	3.3.06

Table 20.47: Property portfolio as at 30 June 2014

Property Type	Owned	Leased	Total
Commercial	3	6	**9**
Industrial	5	1	**6**
Metropolitan Depots	6	2	**8**
Country Depots	20	2	**22**
Total	**34**	**11**	**45**

2010–15 RCP expenditure and performance outcomes for buildings and property
The buildings and property actual/forecast expenditure for the current RCP is $68 million ($ nominal), 24% below the AER allowance of $90 million ($ nominal), refer Table 20.48.

The program for the current RCP was developed on the basis of a rigorous condition-based assessment of all properties within the portfolio. Prior to this, there had been limited data regarding property asset condition or performance. Significant investment has been made during the current period to address the outcomes of the condition-based assessment, highlighted by the construction of a new depot at Holden Hill and a range of other major refurbishment projects.

During the period, a number of planned projects were deferred or alternative approaches adopted. These include:
- an increased number of leased properties where it was more cost-efficient to lease rather than buy;
- delays in land acquisition and construction for depot enhancement in response to the downturn in outer metropolitan residential growth and difficulty in sourcing suitable properties. For example, we recently secured a lease for an industrial property in the north west metropolitan area in the absence of a suitable and cost-effective property for ownership; and
- capital works undertaken at St Marys and Morphett Vale depots to support delivery of services in the Southern metropolitan area. The construction of a new depot at Seaford (Southern area) was deferred until housing development work planned for this growth area increased in line with expectations. Notwithstanding this delay in construction, the land was acquired during this period.

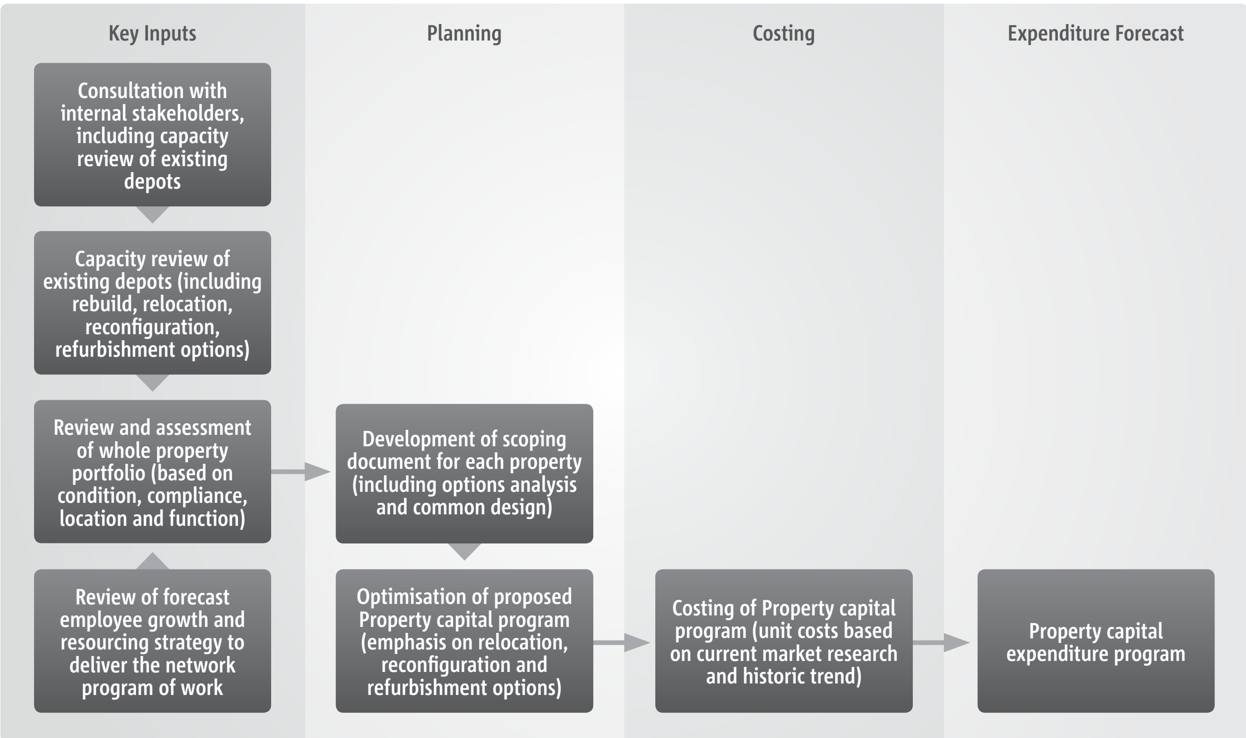
2015–20 RCP expenditure forecasting approach for buildings and property
For the 2015–20 RCP we have again utilised a comprehensive zero-based approach to determining our property and building requirements. This approach is outlined in Figure 20.37.

The forecast is a zero based aggregate of the following:
- consultation with key internal stakeholders, including a capacity review of existing depots;
- an analysis by the business of forecast employee growth and the associated resourcing strategy to deliver the network program of work and the implications of this for the property portfolio;
- a comprehensive assessment of each property location. The approach moved from a strategy based primarily on asset condition (for the current RCP) to one that considered a range of factors relating to location, functionality, condition and compliance;

Table 20.48: Comparison of buildings and property AER allowance and actual/forecast capital expenditure ($ million, nominal)

Building and property ($m)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Allowance	18.0	19.0	23.2	18.0	11.9	**90.1**
Actual/forecast	9.8	19.7	15.6	10.9	11.9	**68.0**

Figure 20.37: Building and property forecasting methodology



- consideration of relevant options and development of individual scoping documents for each property location, including common design and costings. Unit costs were based on current market research and historic trends; and
- preparation of business cases for major spend, including robust options and costing analysis.

Expenditure forecast for the 2015–20 RCP — buildings and property
Buildings and property capital expenditure required for the 2015–20 RCP is forecast at $111.5 million (June 2015) and is shown in Table 20.49.

The provision of a 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 legal and regulatory requirements and provide a safe work environment. Accordingly, our 2015–20 expenditure reflects:

- property refurbishment, upgrades and depot rebuilds required to address the outcomes of our comprehensive location, functionality, condition and compliance based assessment covering:
  - compliance with building codes and WH&S requirements;
  - the alleviation of accommodation constraints;
  - facility upgrades and depot rebuilds ie refurbishment and modernisation;
  - location, accessibility and local pressures on service delivery;
  - additional new properties/buildings on new and existing sites;
  - depot security, associated with mitigating the risk of increasing thefts;
  - employee and public safety;
  - planned building maintenance and repairs; and
  - customer integration and resultant site functionality; and
- forecast employee growth to deliver the significant network program of work over the next period and the associated property requirements.

On this basis, we have identified a need for major investment in property locations such as:

- Seaford — build and fit-out of a new depot, plus the construction of a new industrial facility on vacant land owned;
- Angle Park North and Marleston North — relocation of functions and reconfiguration of existing sites;
- Keswick — ongoing refurbishment program of the corporate head office;
- Nuriootpa — acquisition of land and construction of a larger depot; and
- Clare and Kadina — build and fit-out of new and expanded depots on existing sites.

The remaining capital works program comprises moderate and minor works to address the outcomes of the location, functionality, condition and compliance based assessment of existing properties.

Further detail about the property expenditure program for the 2015–20 RCP can be found in the Strategic Property Plan 2015–2020 at Attachment 16.7. The plan outlines the scope of work which has been considered, including:

- a comprehensive and phased approach to planning in consultation with key internal stakeholders;
- a comprehensive location, functionality, condition and compliance based property assessment, undertaken by MRS Property;
- capacity reviews of all properties, including options analysis (eg rebuild, relocation, refurbishment, acquisition, new build, lease); and
- an analysis and scoping document prepared for each property location with common design and detailed costing.

Costs have been developed using:

- unit costs based on recent market research (competitive tendering) and historic trend with input from independent advisory firm Wilde and Woollard Quantity Surveyors, Rider Levett Bucknall Quantity Surveyors and MRS Property; and
- costing supported by business case analysis for major spend.

20.8.4 Vehicles

We own and operate a large range of vehicles to enable delivery of the network program of work. These include Heavy or Commercial fleet, such as Elevated Work Platforms (**EWPs**) and cranes; and Light and Passenger vehicles. Our fleet composition, as depicted in Figure 20.38, has increased steadily over recent years in line with the increased work program and corresponding employee growth.

Vehicles expenditure and performance outcomes for 2010–15 RCP
The vehicles actual/forecast expenditure for the current RCP is $95 million ($ nominal), above the AER allowance of $89 million ($ nominal), refer Table 20.50.

Table 20.49: Building and property forecast expenditure for 2015–20 RCP (June 2015, $ million)

Property expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Land expenditure	0.6	0.0	0.2	0.2	0.0	**1.0**
Buildings expenditure	13.6	26.5	21.8	26.3	19.1	**107.3**
Easements expenditure	0.6	0.6	0.6	0.7	0.7	**3.2**
Total	**14.8**	**27.1**	**22.6**	**27.2**	**19.8**	**111.6**

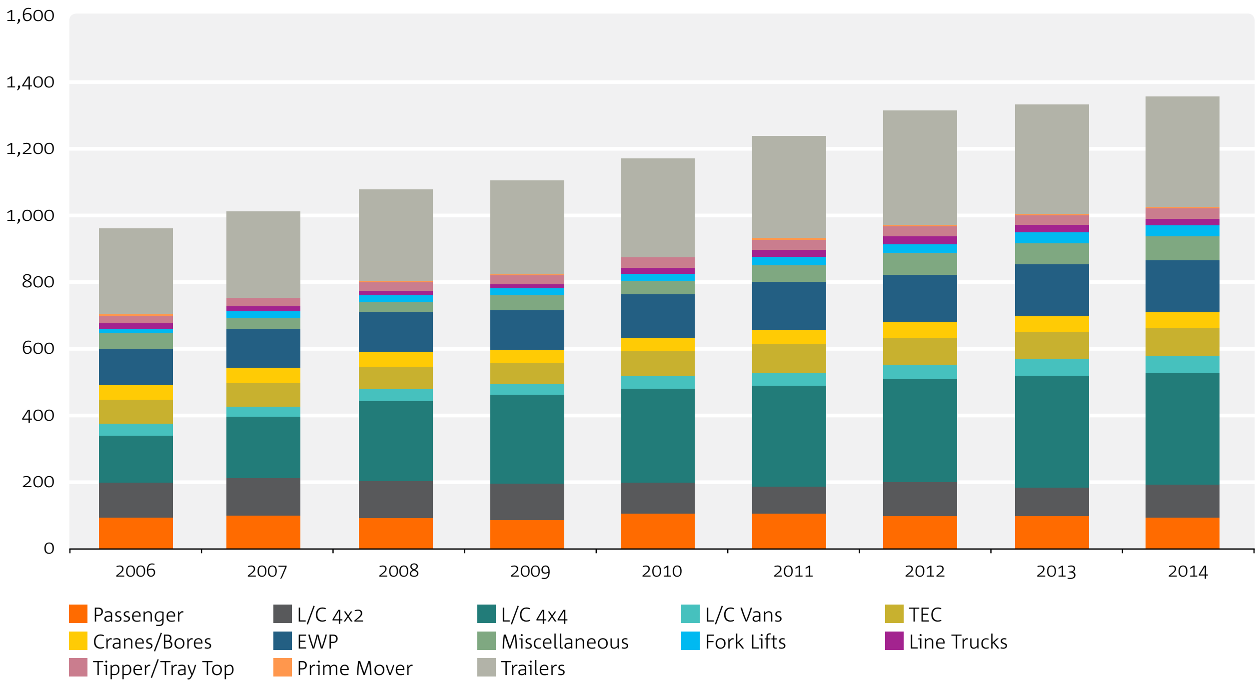
The variance in vehicle expenditure across the period has arisen from the operational decision to change the replacement criteria for EWPs, from 20 years to 10 years and for cranes, from 20 years to 14 years, with effect from 1 January 2012. The changes were considered to be prudent and efficient due to:

- the legislative requirement, and associated costs, for EWPs and cranes to have major inspections (non-destructive testing (**NDT**) rebuilds) once they have been in use for a period of 10 years and every subsequent five years;
- the impact of increasing age on vehicles, including higher maintenance and running costs, safety concerns, deferral of new environmental and safety features, and loss of productivity during rebuild; and
- a comparison with other DNSPs, which showed that we maintained one of the oldest EWP and crane fleets in Australia.

In addition to the delivery of the agreed replacement plan for heavy and light vehicles we have successfully trialled a number of new safety initiatives including:

- Rated Recovery Points and Air Central Tyre Inflation which assist in the recovery of bogged vehicles and towing/entry into inaccessible areas; and
- In Vehicle Management Systems (**IVMS**) which assist us in monitoring mobile employees working alone in remote or risky areas and measuring driver behaviour and vehicle treatment.

Figure 20.38: Fleet composition history



Notes:
- L/C = Light and commercial vehicles
- 4x2 and 4x4 = Number of wheels and driven wheels, respectively
- TEC = Total Employment Contract passenger vehicles

Table 20.50: Comparison of vehicles expenditure AER allowance and actual/forecast capital expenditure ($ million, nominal)

Vehicles expenditure ($m)	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Allowance	13.5	8.3	18.8	24.8	23.6	**89.0**
Actual/forecast	16.5	13.4	18.7	23.2	23.6	**95.4**

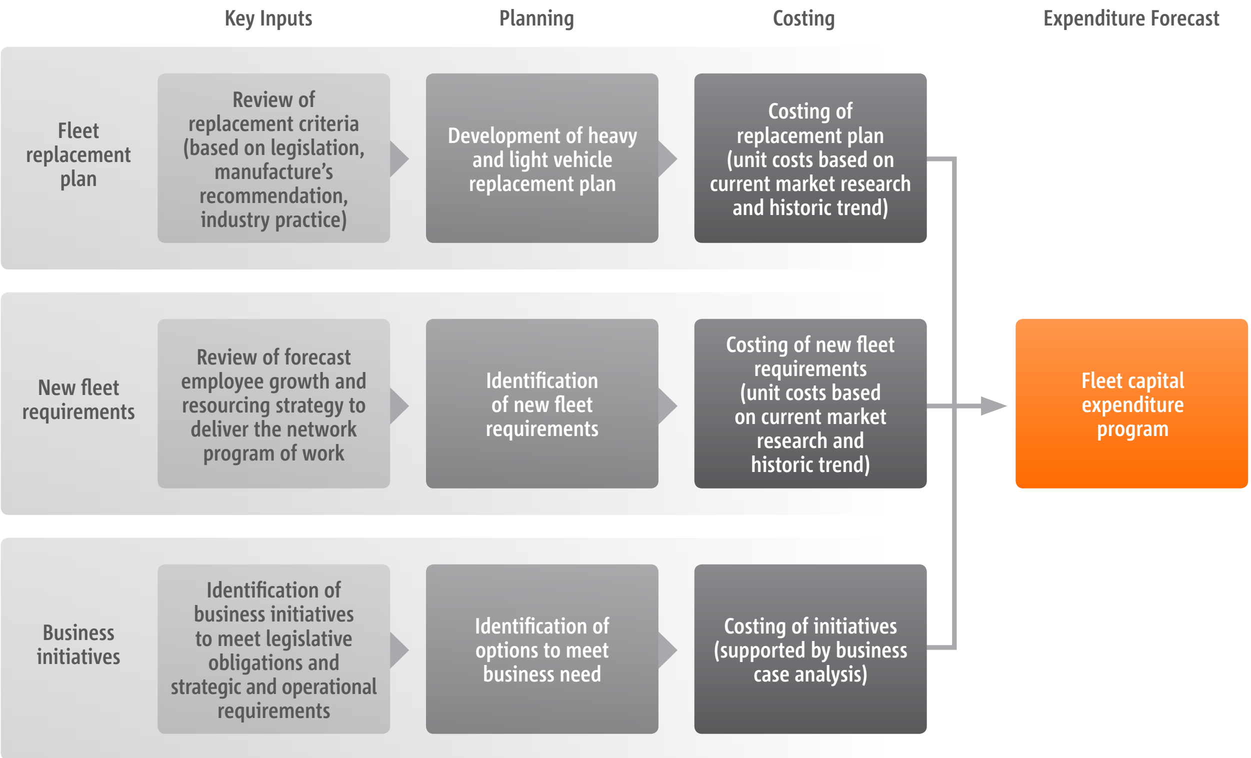
2015–20 RCP expenditure forecasting approach for vehicles

For 2015–20 we have used a comprehensive zero-based approach to determining our fleet requirements. This approach is outlined in Figure 20.39.

Key elements of the expenditure forecast are:

- fleet replacement plan for heavy and light vehicles in accordance with our replacement criteria. The replacement criteria are either age or age and condition based, in accordance with legislative requirements, manufacturers' recommendations or industry practice;
- new fleet requirements driven by forecast employee growth and the associated resourcing strategy to deliver the network program of work; and
- key business initiatives driven by legislative and Workplace health and safety (**WH&S**) obligations and strategic and operational business requirements.

Figure 20.39: Vehicle expenditure forecast methodology



Expenditure forecast for the 2015–20 RCP — vehicles
Forecast vehicle capital expenditure for the 2015–2020 RCP is shown in Table 20.51

SA Power Networks employees travel over 18 million kms during the year. It is critical for the business efficiency that the fleet vehicles are fit for purpose, are reliable and importantly are in good condition to ensure safe travel and work operation. Accordingly the expenditure for the 2015–20 RCP reflects:

- replacement criteria driven by legislative requirements, manufacturers' recommendations and industry practice. During the next RCP, we propose to change the replacement criteria for other commercial vehicles from 20 years to 15 years, and passenger and light vehicles from five years to four years. This change is driven by an increasing number of vehicles being replaced early due to poor condition and safety concerns. The change will ensure that our commercial vehicles are fit-for-purpose, legislatively compliant and provided to the business in a timely manner to enable the efficient and effective delivery of the network program of work. In addition, a comparison with other DNSPs has shown that we maintain one of the oldest aged and condition based commercial and light and passenger fleets in Australia. The change in replacement criteria will bring us in line with current industry practice;
- new fleet requirements driven by the resourcing strategy to deliver the network program of work across the next RCP;
- compliance with vehicle and WH&S related legislative requirements, standards and codes of practice;
- advances in vehicle and in-vehicle technology, which provide opportunities to ensure a safe working environment for our highly mobile workforce. IVMS promotes employee safety, welfare and mobility in response to WH&S legislative requirements and our Mobility Strategy. The IVMS allows for the transfer of real time data regarding employee welfare and driving behaviour (including safety alerts) from a mobile employee in the field to a central location. The system will provide improved monitoring of safety of remote workers. The IVMS is proposed to be rolled-out across 2016/17 and 2017/18 following a successful pilot and trial of the system during the current RCP; and
- installation of vehicle weighing mechanisms at our depots to ensure ongoing compliance with mandatory safety requirements related to vehicle weight. The objective is to provide a mechanism to ensure that vehicles are not overloaded thereby improving the safety of our workers and mitigating the risk of vehicles being defected due to non-compliance with *Road Traffic Act* regulations.

Further detail about the fleet expenditure program for the 2015–20 RCP can be found in the Strategic Fleet Plan 2015–2020 provided as Attachment 20.26. The plan outlines the scope of work which has been considered:

- planning undertaken in accordance with the Fleet Lifecycle — Quality Manual;
- replacement criteria aligned to legislative requirements, manufacturers' recommendations and industry practice;
- benchmarking analysis of replacement criteria against other DNSPs;
- new fleet requirements driven by resourcing strategy to deliver the network program of work;
- new fleet requirements identified based on forecast employee growth and historic ratio of personnel to vehicle;
- new business initiatives driven by legislative and WH&S requirements; and
- identification and analysis of options to meet business need.

Costs have been developed using:

- replacement unit costs based on current market research (competitive tendering) and historic trend;
- sensitivity costing analysis of proposed changes to replacement criteria to ensure cost-efficiency;
- costing supported by business case analysis; and
- business initiative costing based on current market research (vendor research and competitive tendering).

Table 20.51: Vehicle forecast expenditure for 2015–20 RCP (June 2015, $ million)

Vehicle expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Vehicle replacement	36.7	20.9	15.3	18.5	22.4	**113.8**
New fleet	1.7	5.9	8.2	5.9	3.9	**25.6**
Safety initiatives	0.7	2.3	2.4	1.2	0.0	**6.6**
In-Vehicle Management System	0.7	1.1	1.2	0.0	0.0	**3.0**
Vehicle weight compliance	0.0	1.2	1.2	1.2	0.0	**3.6**
Total vehicles	**39.1**	**29.1**	**25.9**	**25.6**	**26.3**	**146.0**

20.8.5
Non-network other

Business change activities

It has been recognised by many organisations that managing change in businesses is becoming increasingly challenging and complex. Reports[64] outlining the need to increase internal business change capability to address the rapidly changing technology and increasing growth in data volumes, identifies that investment is required to build enterprise wide change capabilities. SA Power Networks will continue to build on the internal Business Change Management capability developed in the current RCP. This will ensure we can respond efficiently to our customers requirements as they demand seamless experiences across multiple channels of engagement, specifically by aligning client-facing and internal business processes across our organisation.

As our proposed portfolio of work associated with technology change increases, business costs covering activities such as change management and business process changes associated with implementing projects rise.

The business change activities have been individually costed although they are part of the total cost of ownership of projects, listed in Section 20.8.1, and are included in the individual business cases. The business change costs are to cover extra labour resources required within our business units to ensure the IT capability changes are managed and embedded, effectively and efficiently.

Further detail on the business cases and the change management activities can be found in Attachment 20.28.

Expenditure forecast for the 2015–20 RCP — other — business change activities

The non-network other business change activities expenditure required for the 2015–20 RCP is $45.8 million (June 2015 $) and is summarised in Table 20.52. This is primarily driven by the increased IT developments that will position SA Power Networks for the future.

Plant and tools

2010–15 RCP expenditure and performance outcomes — other — plant and tools

The plant and tools actual/forecast expenditure is $22.6 ($ million, nominal), 37% below the AER allowance of $36.0 ($ million, nominal), as shown in Table 20.53.

The forecast underspend is largely attributable to the reallocation of funds to purchase additional vehicles such as EWPs and cranes arising from the increased volume of asset replacement works during the current RCP.

Expenditure forecast for the 2015–20 RCP — other — plant and tools

Forecast plant and tools capital expenditure for the 2015–20 RCP is shown in Table 20.54.

The forecast expenditure level is marginally higher than the current RCP and is driven by an increase in Trade Skilled Workers (**TSWs**) and vehicles which need to be fitted with appropriate equipment; specialist equipment arising from changes in technology or technical requirements; and the need to replenish tools for safety reasons.

Superannuation

Superannuation expenditure relates to the capital allocation of the superannuation contributions that we are required to make to the Electricity Industry Superannuation Scheme (EISS) and other superannuation schemes in the 2015-20 RCP.

The negative adjustment of $47.9 million (June 15 $) over the five year period reflects the lower contributions that commenced part way through the 2013/14 regulatory year. Our Revised Proposal will incorporate new contribution rates to apply from 1 January 2015 as determined by the EISS actuary and Board, refer to Section 21.6.4 for more details.

Table 20.52: Forecast business change activities for 2015–20 RCP (June 2015, $ million)

Business change activities expenditure	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Business change activities	9.8	13.5	9.5	8.3	4.9	**45.8**

Table 20.53: Comparison of plant and tools AER allowance and actual/forecast capital expenditure ($ million, nominal)

Plant and Tools	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Allowance	7.5	6.9	6.6	8.0	7.0	**36.0**
Actual/Forecast	5.2	2.7	3.1	5.6	6.0	**22.6**

Table 20.54: Forecast plant and tools expenditure for 2015–20 RCP (June 2015, $ million)

Non-Network Other	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Plant and Tools	5.3	5.3	5.3	5.3	5.3	**26.7**

64 IBM Global Business Services, Executive Report, Making change work … while the work keeps changing, How Change Architects lead and manage organizational change.

20.9

Alternative Control Services capital expenditure

Alternative Control Services (**ACS**) capital expenditure relates to metering services provided by SA Power Networks. Metering capital expenditure comprises the costs of installing new meters, of replacing non-compliant and failed meters, and of making material repairs to metering installations. Meter replacements are driven by regulated testing requirements. (Note that meter testing costs are a component of ACS operating expenditure.)

SA Power Networks is required to comply with the requirements of the Responsible Person role contained in the NER, and other technical and regulatory requirements. In addition to meeting these requirements, SA Power Networks' metering services aim to ensure that relevant expenditure is prudent, and efficient and focussed on ensuring that our metering equipment:

- is safe and accurate;
- supports our network pricing and tariff strategies;
- supports our network load management objectives and strategies; and
- is reasonably capable of efficiently supporting current and expected future relevant market and/or customer requirements.

Metering capital expenditure for ACS in the next RCP will be impacted by two key step changes:

- changes to the AER's F&A[65] for SA Power Networks comprising the reclassification of Type 5 metering services, meter installation services, and energy data services as ACS;
- the metering-related impact of the introduction of capacity tariffs as described in Chapter 14; and
- the introduction of 'smart ready' meters on a new and replacement basis.

20.9.1
Proposed capital expenditure

The total forecast capital expenditure related to the provision of ACS metering services for each year of the 2015–20 RCP is shown in Table 20.55.

These forecasts are built up in our ACS Metering Pricing Model, provided as Attachment 29.4.

The capital expenditure forecasting methodology is a 'bottom-up' approach and includes determining forecast volumes by meter type, for new and replacement meter situations and meter installation upgrades and the average unit cost for these services.

Volume forecasts are based on a combination of historical trend data, future asset management plans and independent (BIS Shrapnel) economic forecasts. Unit costs are based on the weighted average cost of SA Power Networks' meter equipment, the meter mix, on-costs and installation labour costs.

Our forecasting methodology is explained in detail in ACS Metering Tariff Development Methodology Attachment 29.3.

Cost reflective tariffs and 'smart ready' meters

As noted in Chapter 14 of this Proposal, SA Power Networks proposes to commence a transition to capacity based tariffs for residential and small business customers in the next RCP. To support such tariffs and avoid wasted further investment in obsolete accumulation meters, SA Power Networks proposes that all new and replacement meters installed in the next RCP will be meters that:

- are capable of recording interval data and measuring maximum demand; and
- are designed to be upgradable in future with the addition of an optional telecommunications module to enable remote reading and other advanced functions.

Table 20.55: Forecast ACS metering services capital expenditure for the 2015–20 RCP (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
New connections expenditure	2.7	2.7	2.8	2.8	2.8	**13.8**
Replacements expenditure	7.1	6.8	6.9	7.6	4.2	**32.6**
IT Infrastructure expenditure	0.2	0.2	1.7	0.2	0.2	**2.6**
Customer initiated work	5.7	7.4	12.0	11.9	12.5	**49.4**
Total gross capital expenditure	**15.7**	**17.1**	**23.3**	**22.5**	**19.7**	**98.4**
Customer contributions	(5.7)	(7.4)	(12.0)	(11.9)	(12.5)	**(49.4)**
Total net capital expenditure	**10.0**	**9.8**	**11.3**	**10.6**	**7.3**	**49.0**

65 AER, *Final framework and approach for SA Power Networks RCP commencing 1 July 2015*, April 2014

The cost of such 'smart ready' meters is now only slightly higher than the cost of basic accumulation meters. Installing such meters as standard is a key enabler for the efficient introduction of capacity tariffs. It also avoids imprudent investment in obsolete equipment, and supports the South Australian Government's proposed policy for new and replacement meters[66]. The key areas of ACS metering services capital expenditure are discussed below.

New connections expenditure
New connection capital expenditure relates to new customer installations. Proposed new connection capital expenditure for the 2015–20 RCP is approximately $3 million per annum. This includes a small unit cost increase reflecting the cost differential between smart ready and accumulation meters. We forecast an increase in the underlying volume of new connections, which equates to a capital expenditure uplift of approximately $0.7 million per annum.

Replacement expenditure
The key drivers of replacement capital expenditure are compliance (deteriorating accuracy indicated by meter testing) and the increasing failure of one type of early model electronic meter, which together make up 80% of replacement capital expenditure. Defective electronic meter replacements are due to a recently identified compliance issue and are therefore a new cost in 2014/15. They will drive an increase in meter replacements of about $2.4 million per annum on average. Further details are set out in SA Power Networks' Meter Asset Management Plan, which is provided as Attachment 21.24.

IT infrastructure expenditure
For capacity tariffs to be effective, relevant meters must be read monthly. IT infrastructure capital expenditure reflects a $1.5 million one off investment in 2017/18 required to facilitate the proposed transition to monthly meter reading, discussed in Chapter 21.

IT infrastructure capital expenditure reflects the change of classification of energy data services from SCS to ACS from July 2015.

Upgrades expenditure
Customer initiated meter upgrades are treated as Negotiated Distribution Services (**NDS**) in the current RCP, but will be classified as ACS from July 2015. This represents a significant uplift in ACS gross capital expenditure from 2015/16, however there is no impact on net capital expenditure as these costs will be offset by customer contributions.

Customer initiated meter upgrade capital expenditure reflects a small uplift in import/export meter installations in 2016/17, and a larger increase arising from customers upgrading their metering to enable them to take advantage of capacity tariffs. This latter impact takes material effect from 2017/18. The derivation of these upgrade quantity estimates is described in further detail in SA Power Networks' Tariff and Metering Business Case, which is provided as Attachment 14.3.

20.10

Program deliverability

Our capital and operating expenditure forecasts, as detailed earlier in Chapter 20 and the following Chapter 21, represent a significant increase in the program of work when compared to the current RCP. This is primarily driven by higher capital investment in Asset Replacement; Bushfire programs; Information Technology and Demand Side Participation. Further our ageing workforce, of whom approximately 10% are aged 60 and over, will also present us with the challenge of replacing these personnel during the upcoming RCP. As such we will continue our transitioning to retirement arrangements to ensure that where possible skills and knowledge are transferred to existing and new staff. This will be complemented by training programs and targeted recruitment to bring into the organisation the new skills required to meet the changing customer demands associated with the growing impact of digital and new technologies.

We have developed strategies to specifically address the delivery of our Network and Information Technology programs of work given the uplift in resources required to deliver these services.

20.10.1
Network program

At the commencement of the current RCP we implemented a revised field resourcing strategy to deliver the step increase in the Network program of work. This strategy incorporated the establishment of panel contracts to cover resourcing requirements primarily for design, substation and power line construction and maintenance works. The initial two years of the current RCP required a high level of substation construction and maintenance to meet the demand for network growth, which has a relatively low resource component of the capital spend. There has however been a shift since then to the more labour intensive power line asset refurbishment works. This trend is not only forecast to continue but significantly increase over the next two RCPs, as outlined in Section 20.5. This work is undertaken by Power Line Trade Skilled Workers (**TSWs**), through a combination of internal and external outsourced resources above current baseline levels. Figure 20.40 shows the increase of approximately 200 TSW resources required to deliver the power line related construction and maintenance functions.

66 *South Australian Policy for New and Replacement Electricity Meters, Discussion Paper*, Government of South Australia, Department for Manufacturing, Innovation, Trade, Resources and Energy, January 2014.

Whilst we will continue our apprentice program the impact will effectively be neutral as this will only offset the forecast attrition rates of older workers. In developing the strategy to deliver the required resourcing level we have considered alternative options including:

- maintaining internal resource levels, adjusted for projected apprentice growth and attrition, and outsourcing the balance;
- increasing internal resources through the recruitment of TSW's; and
- reducing current internal resource levels and thereby outsourcing an even greater proportion of work.

We have determined that the recruitment of an additional 90 TSW's over the 2015-20 period and outsourcing the balance as the most prudent and efficient approach. The key considerations included:

- market supply of TSW labour;
- ageing workforce;
- work program type;
- internal and outsourced labour rates; and
- support functions such as training, accommodation (depot) requirements and contract management.

As we will progressively recruit TSWs over the period, in line with the work program profile, we will work with our panel contractors to supply the additional resources. This is shown in Figure 20.41.

We will invest in additional vehicles and equipment, plus construct new depots and expand some of our existing depots to adequately accommodate the increased level of internal resources.

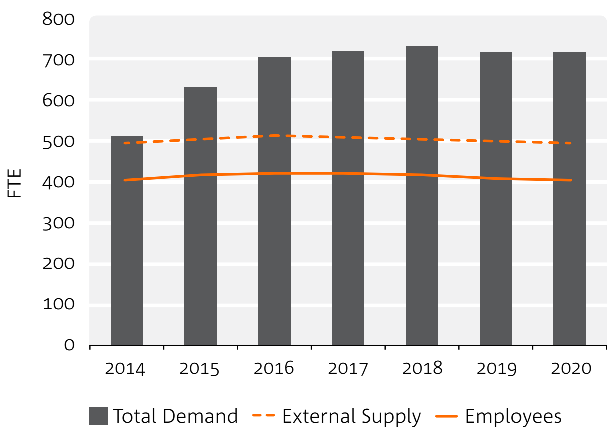
More detail is provided in the supporting Network Program Deliverability strategy document at Attachment 20.27.

20.10.2
Information Technology program

We have experienced an increase in demand in IT services during the current RCP, and to assist in the delivery of this an IT Transformation program has been implemented. This program has resulted in an IT organisation better positioned to deliver a capital and operating program congruent with the needs of the business. A key feature of this transformation is the implementation of a fit-for-purpose IT Operating Model, including a significant shift away from a highly in-sourced and tactical contract labour-heavy workforce. Instead we will leverage strategic partnerships to assist with technology and solutions that are outside of core capabilities.

The resource requirements derived from the 2015–20 RCP forecast are significant in comparison to historical demand for IT resources. The total effort to deliver the capital and operating forecast is almost double that of the 2010–15 RCP, ranging from 353 to 360 full time equivalent (**FTE**) resources per year.[67]

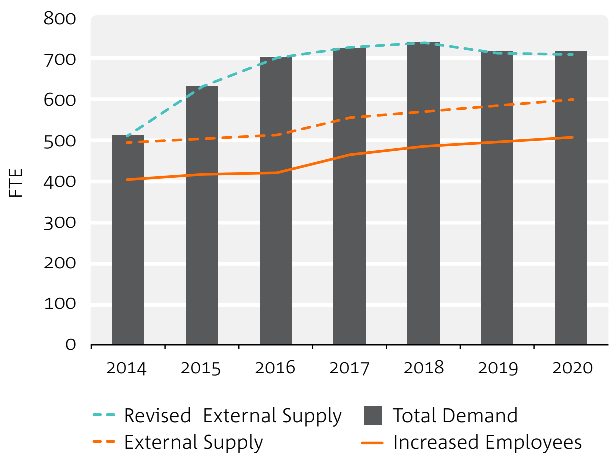
Figure 20.40 Trade Skilled Workers — supply and demand model summary



Note: FTE = Full time equivalent employees

SOURCE: SA POWER NETWORKS ANALYSIS 2014

Figure 20.41: Trade Skilled Workers — resourcing summary



SOURCE: SA POWER NETWORKS ANALYSIS 2014

67 Excludes non — IT resource contribution to IT capital projects

Appropriate sourcing methods to meet this demand were investigated with respect to the mix of internal labour, supplementary labour and professional/managed services, with three options finally considered:

- **Option 1** — Maintain in-sourced FTE levels (inclusive of 20% supplementary labour) at the 2014 Q2 IT Operating Model target of 155 FTEs;
- **Option 2** — Increase in-sourced IT FTE levels in proportion to the forecast growth in total organisational FTEs (as per 2013 and 2014 Gartner Worldwide Utilities benchmark of IT FTEs at 6.6% of total FTEs); and
- **Option 3** — Increase in-sourced FTE levels by the amount required to limit outsourcing levels to 30% for IT Operations and 65% for IT Capital Program delivery, based primarily on risk mitigation factors.

Option 3 is the proposed option on the basis that:

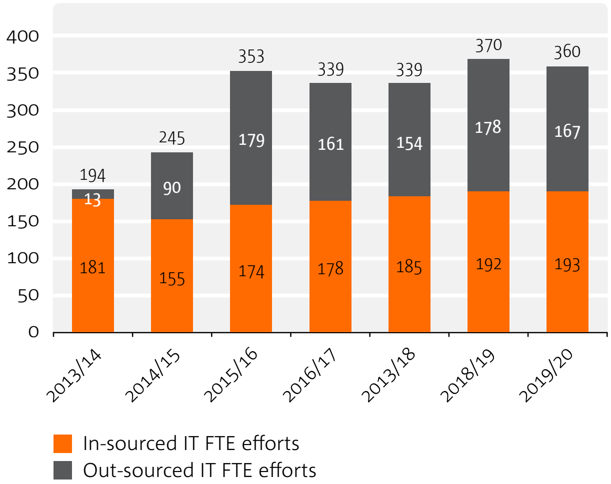
- it is linked to the forecast IT effort, rather than organisational wide benchmarks unrelated to effort. Option 3 therefore takes into consideration the shift in the organisation's strategic focus on IT as a means to improving business outcomes;
- IT continues to support the objectives of the IT Transformation program by:
  - limiting the use of supplementary labour to 20% of in-sourced FTEs;
  - leveraging external professional services in the delivery of the capital program where appropriate, but at the same time ensuring the in-sourced workforce has sufficient capacity to contribute the minimum levels of involvement required to facilitate successful project outcomes (35%); and
  - seeking opportunities to transition operational activities to external managed services, but doing so in a methodical and well planned fashion and limiting outsourced operational services to 30% of total operational IT effort as a risk mitigation strategy.

The outcome in terms of the number of in-sourced and out-sourced FTEs required to deliver option 3 is summarised in Figure 20.42.

As detailed in Section 20.8.1, portfolio analysis is undertaken to identify critical dependencies and enabling capabilities required to be implemented in order to deliver the most efficient outcomes for the organisation.

The detailed delivery plan outlining how we will deliver the work program can be viewed in Attachment 20.43 — IT Sourcing and Resourcing Plan.

Figure 20.42: Information Technology resourcing summary



SOURCE: SA POWER NETWORKS ANALYSIS 2014

21
Forecast operating expenditure

21

In this chapter, we detail the operating expenditure forecasts for the 2015–20 RCP. We describe the NER requirements, 2010–15 RCP outcomes, forecast development processes, and then outline the components of the forecast.

Standard Control Services (**SCS**) are subject to the AER's 'base-step-trend' operating expenditure forecasting approach, and are discussed in the first sections of this chapter. This chapter concludes with discussion of the operating expenditure forecast for Alternative Control Services (**ACS**).

21.1

Rule requirements

Clause 6.5.6(a) of the NER requires SA Power Networks to include in our building block proposal a total forecast of the operating expenditure for the 2015–20 RCP which we consider is required in order to achieve each of the following operating expenditure objectives:

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; and
    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.

In addition, clause 6.5.6(b) of the NER states that the forecast of required operating expenditure that is included in our building block proposal must:

1. comply with the requirements of any relevant regulatory information instrument;
2. be for expenditure that is properly allocated to SCS in accordance with the principles and policies set out in the Cost Allocation Method (**CAM**) for us; and
3. include both:
    a. the total of the forecast operating expenditure for the 2015–20 RCP; and
    b. the forecast operating expenditure for each regulatory year of the 2015–20 RCP.

Further, clause 6.5.6(c) of the NER states that the AER must accept our proposed operating expenditure forecast if the AER is satisfied that the total of the forecast operating expenditure for the 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 requires that, in deciding whether or not it is satisfied that the total of our forecast operating expenditure reasonably reflects the operating expenditure criteria, the AER must have regard to the following operating expenditure factors:

1. the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient DNSP over the relevant RCP;
2. our actual and expected operating expenditure during any preceding RCPs;
3. the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by us in the course of our engagement with electricity consumers;
4. the relative prices of operating and capital inputs;
5. the substitution possibilities between operating and capital expenditure;
6. whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to us under clauses 6.5.8 or 6.6.2 to 6.6.4;
7. the extent the operating expenditure forecast is referable to arrangements with a person other than us that, in the opinion of the AER, do not reflect arm's length terms;
8. whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b);
9. the extent we have considered, and made provision for, efficient and prudent non-network alternatives;
10. any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s); and
11. any other factor the AER considers relevant and which the AER has notified SA Power Networks in writing, prior to the submission of our revised Regulatory Proposal under clause 6.10.3, is an operating expenditure factor.

We consider that we have demonstrated in this chapter and the referenced attachments that the proposed levels of expenditure meet the operating expenditure criteria, and must therefore be accepted as part of the AER's Distribution Determination.

21.2

Current period performance

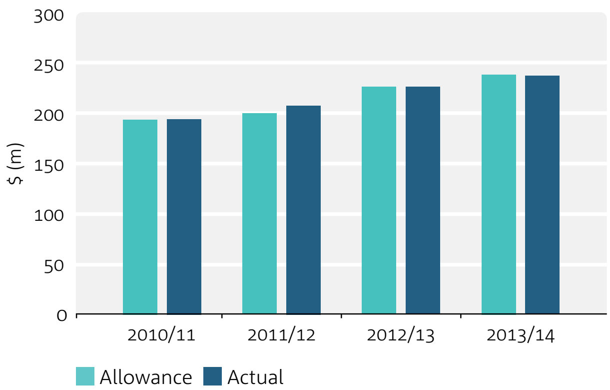
We have demonstrated our ability to prudently and efficiently manage the delivery of SCS during the current RCP. This is evidenced by the number of significant challenges we have encountered, some out of our control, that have directly impacted on the operating costs of providing these services. In particular:

- Guaranteed Service Level (**GSL**) payments have been high due to the extreme weather events across the current RCP;
- the breaking of the 'millennium drought' in 2010 had a substantial impact on our vegetation management program. An AER approved pass-through application in July 2013, for the 2012/13 to 2014/15 period, has not completely offset the increased costs that we have incurred as we work to ensure that we have a compliant vegetation management program by 30 June 2015; and
- the volume of solar photovoltaic (**PV**) system installations has far exceeded the forecast take up volumes, largely driven by the State Government Feed-In Tariff legislation. This has resulted in increased customer services costs in relation to processing and administering the installations.

Despite the increased costs associated with these items, by the end of the 2010–15 RCP, we forecast that our total operating expenditure will be in line with the total allowance of $1.1 billion for the period.

As shown in Figure 21.1, operating expenditure has followed an upward trend consistent with the allowance. This trend will continue in the forthcoming RCP as we continue to meet our regulatory and other obligations.

Figure 21.1: SCS operating expenditure actual vs allowance 2010–14 ($ nominal)



SOURCE: SA POWER NETWORKS ANALYSIS 2014

In accordance with NER Schedule 6.1.2(7) a comparison with the operating expenditure for each regulatory year of the 2005–10 RCP is summarised in Attachment 20.73.

21.3

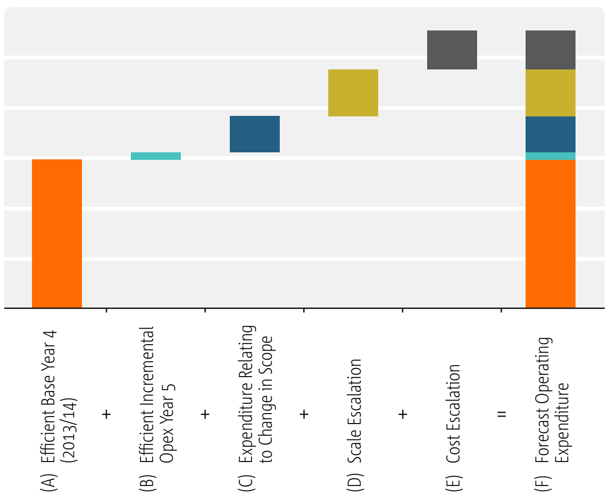
Operating expenditure development process

The development of our operating expenditure forecast for the 2015–20 RCP, is based on the 'base-step-trend' approach. We have:

- nominated 2013/14 as the efficient revealed base year;
- adjusted the base year for the efficient incremental operating expenditure in the final regulatory year of the 2010–15 RCP (ie 2014/15);
- calculated the five year expenditure using the adjusted base year costs;
- adjusted the base year for unusual items that occurred in 2013/14;
- determined the additional five year operating expenditure for step changes in the scope of activities carried out in delivery of SCS that have not been incurred in the base year; and
- applied the rate of change formula to each category of operating expenditure, as appropriate, to account for the increases in the:
  - scale of operations (output growth) which drive a change in the volume of existing activities carried out; and
  - real price cost escalators relating to the unit cost of labour, materials, services and land, driven generally by economic and market factors.

Our base year costs have been calculated in accordance with our approved CAM, provided at Attachment 20.7. Figure 21.2 shows our operating expenditure cost build up process.

Figure 21.2: SCS operating expenditure forecast process



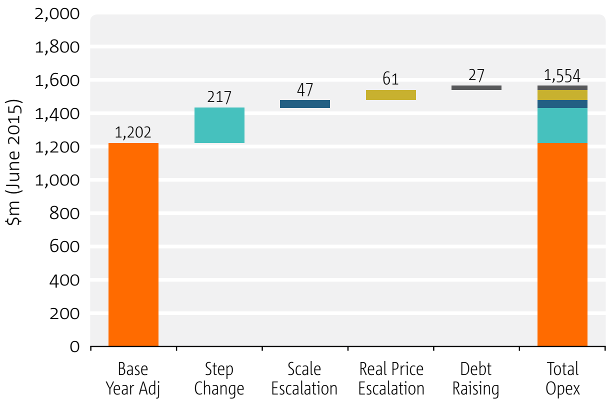
SOURCE: SA POWER NETWORKS EXPENDITURE FORECAST METHODOLOGY, ATTACHMENT 7.5

21.4

Summary of proposed operating expenditure for 2015–20 RCP

Figure 21.3 shows our forecast of the total operating expenditure that we consider will be required during the 2015–20 RCP in order for us to achieve the NER operating expenditure objectives.

Figure 21.3: SCS operating expenditure 2015–20



SOURCE: SA POWER NETWORKS ANALYSIS 2014

The yearly profile of this proposed operating expenditure over the five years 2015–20 is shown in Table 21.1.

The following sections provide details of each element of the operating expenditure build up.

21.5

Efficient base year (being 2013/14) and base year cost adjustments

The incentive nature of the economic regulation of distribution network businesses (including the ex-ante Efficiency Benefit Sharing Scheme (**EBSS**) incentive) provides an ongoing effective incentive to continually seek to operate these businesses as efficiently as possible whilst delivering on regulatory obligations and meeting customers' service expectations.

SA Power Networks has prided itself on being an efficient network business and we have nominated 2013/14 as the efficient (revealed) base year. We consider that the 2013/14 regulatory year is best suited as the base year, because it is:

- the most recent full regulatory year of actual reported performance, with audited regulatory accounts provided at the time of submission of this Proposal; and
- representative of the underlying operating and economic conditions experienced within the current RCP and can reasonably be expected to represent these underlying conditions that will prevail during the 2015–20 RCP.

The consistency of the 2013/14 operating expenditure with both the prior year expenditures and the current AER allowances and our analysis (see Figure 21.4) of the publicly available AER Economic Benchmarking data (that shows that we operate as the most efficient network business in the NEM) is clear evidence that utilising 2013/14 as the base year is appropriate. We are confident that the operating expenditure in the 2013/14 regulatory year provides an efficient base from which to forecast the operating expenditure required to fulfil our obligations with respect to SCS during the 2015–20 RCP.

The 'Base' in Table 21.1 consists of the 2013/14 unadjusted operating expenditure of $242.8 million (June 2015 $) plus adjustments of $4.6 million (June 2015 $) for the efficient incremental operating expenditure for 2014/15 (for real costs and scale escalation approved in the 2010 determination).

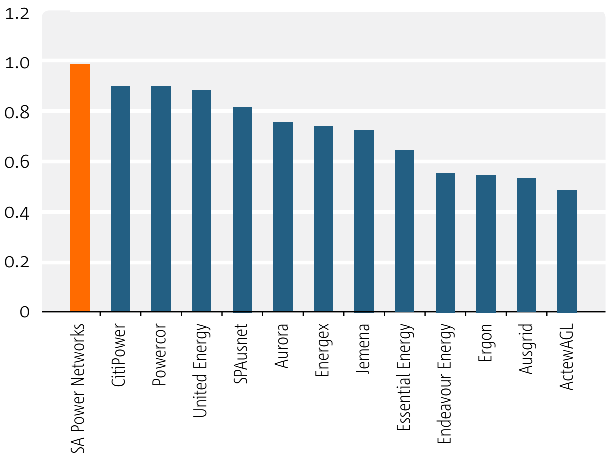
Table 21.1: SCS operating expenditure costs 2015–2020

June 2015 ($m)	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 Adjustments	(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**
Scale Escalation	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**
Debt Raising	4.8	5.1	5.4	5.7	6.0	**27.0**
Total	**285.7**	**298.9**	**315.9**	**324.5**	**329.1**	**1,554.1**

Table 21.2: Base Year cost adjustments for SCS 2015–20

June 2015 ($m)	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Self insurance	(3.2)	(3.2)	(3.2)	(3.2)	(3.2)	**(16.0)**
Metering reclassification	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	**(11.0)**
Regulatory Proposal	(3.0)	(3.2)	(1.5)	0.7	(1.2)	**(8.2)**
Distribution Licence fee	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	**(5.5)**
Demand Management Incentive Allowance	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	**(4.5)**
Non-network solution	0.2	0.2	0.3	0.3	0.4	**1.4**
Property	0.4	0.4	0.4	0.4	0.4	**2.0**
Finance adjustments	1.4	1.4	1.4	1.4	1.4	**7.0**
Total	**(8.4)**	**(8.6)**	**(6.8)**	**(4.6)**	**(6.4)**	**(34.8)**

Figure 21.4: Multilateral Total Factor Productivity (MTFP) 2013



SOURCE: HUEGIN ANALYSIS BASED ON AER 2013 PREFERRED SPECIFICATION MTFP MODEL ADJUSTED FOR CUSTOMER DENSITY AND AER MAY 2014 ECONOMIC BENCHMARKING DATA.

Further analysis and discussion of benchmarking outcomes is contained in Huegin's benchmarking report at Attachment 4.1.

Whilst the 2013/14 expenditure is being used as our base year, in developing our operating expenditure forecast for 2015–20 we are required to make adjustments to the base year where there are expenditures of an unusual nature that are likely to understate/overstate our longer-term efficient costs. Table 21.2 summarises the adjustments to the base year expenditures for each regulatory year of the 2015–20 RCP for these items.

The bases for the adjustments to the base year costs for each of the items outlined in Table 21.2 are as follows:

Self insurance — We currently retain, or self-insure:

- where no insurance is available, or insurance is not available on economic terms;
- the amount of deductibles under our insurance policies; and
- any amount above insurance policy limits.

Consistent with the AER definition for the 2010 Determination, the self-insurance cash forecast relates to claims of $100,000 or greater, arising from the above circumstances and workers compensation claims. The 2013/14 base year cost is $5.1 million, adjusted to June 2015 $, which is $3.2 million higher than the average expenditure over the first four years of the current RCP and accordingly the base year amount has been reduced by $3.2 million. Further detail is provided within the insurance section of the Reset RIN[68].

68 Tab 2.15 'Commercial insurance and self insurance'

Metering reclassification — In its 2015–20 Framework and Approach Paper (**F&A**) the AER has reclassified Type 5 and 6 metering related services as ACS. The Type 6 metering reclassification primarily impacts on meter data management services relating to back office support information systems and personnel. The applicable 2013/14 base year costs to be transferred to ACS are $2.2 million. A corresponding increase in these costs has been included in ACS, refer Section 21.13.

Regulatory Proposal — This Proposal (for the 2015–20 RCP) has involved considerable expense, over a three year period. The 2013/14 base year incorporates higher expenditure, and therefore a negative change is applied for those years in the 2015–20 RCP during which such a level of expenditure will not be incurred. The 2013/14 base year adjustment equates to an average reduction of $1.6 million over the 2015–20 RCP.

Distribution Licence fee — Under the South Australian *Electricity Act 1996* we must hold a licence to operate the distribution network and are charged an annual licence fee. On 11 September 2014 the SA Minister for Mineral Resources and Energy advised that the SA Power Networks annual licence fee would be reduced by $1.1 million from 1 July 2015, refer Attachment 21.21.

Demand Management Incentive Allowance — The 2015–20 F&A (page 14) provides for a Demand Management Incentive Allowance (**DMIA**) of $3.0 million to apply in the period. This allowance is for the development of initiatives to lower or shift peak demand. The 2013/14 base year includes $1.5 million (June 2015 $) for demand management expenditure being $0.9 million higher than the $0.6 million annual allowance.

Non-network solution — The Bordertown non-network solution, previously assessed under the ESCoSA Guideline 12 process, was implemented in 2013 to resolve a forecast overload in the Bordertown region. This solution has deferred, until at least September 2020, approximately $26 million in capital 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 are forecast to be on average $0.3 million per annum higher than the 2013/14 base year costs of $0.3 million.

Property — An additional depot property has been leased in the north western Adelaide suburb of Wingfield. This depot will improve customer service and ease safety issues due to congestion at other depots. The lease arrangement was entered into as a suitable property could not be purchased in the timeframe required. The lease commenced in the latter part of the 2013/14 year. The adjustment of $0.4 million per annum to the costs of $0.1 million in 2013/14 has been made to reflect the full year costs for this property incorporating lease payments and outgoings.

Financial adjustments — One-off accounting adjustments relating to provision changes such as long service and annual leave have been included in the 2013/14 regulatory accounts. We have forecast the real cash operating expenditures associated with such transactions. We have adjusted the base year to offset the negative 2013/14 base year amount of $1.4 million to ensure that the net forecast expenditure in this cost category from 2015/16 to 2019/20 is zero.

21.6

Step changes to operating expenditure for 2015–20 RCP

In developing our expenditure forecasts that extend into the future we seek to identify through a thorough environmental scan events that are foreseeable and to forecast their impact by relying on the best information at hand. The natural consequence of these factors is that accuracy of forecasting becomes more difficult beyond a three year planning horizon and we have adopted a necessarily conservative approach to forecasting these costs. To the extent that unforseen and uncontrolled events occur reliance will be placed on the cost pass-through provisions contained in Rule 6.6.1 of the NER and outlined in Chapter 22. However, unless the materiality threshold for pass-through events is reached, this can result in SA Power Networks incurring expenditures which have not been forecast and allowances not provided.

Consequently, we consider we will incur increased operating expenditures during 2015–20 which are not included in the 2013/14 base year expenditure. These costs relate to:

- changes in legal and regulatory obligations;
- operating costs arising from proposed capital expenditure;
- delivering on consumer expectations identified during our Customer Engagement Program; and
- financing related matters.

Importantly in assessing these changes to our operating costs we have undertaken a thorough analysis, investigation and rigorous review to ensure alignment with the NER, and consistency with key assumptions and cost drivers. Careful attention has been given to ensuring that no output growth is incorporated into the changes in scope, and that the step changes therefore reflect genuine new requirements or activities, or a fundamental shift in operations and do not in any way constitute 'more of the same'.

For customer driven initiatives we have drawn the extent and rationale for these initiatives from our comprehensive Customer Engagement Program titled 'TalkingPower', which has enabled our customers and the South Australian community to articulate their sentiments and opinions, and which have been described in Chapter 6 of this Proposal and further expanded upon in each of the Chapters 9 to 16.

Attachment 21.13 provides detailed supporting information for each of the step changes. It specifically addresses the key criteria outlined in the Expenditure Forecast Assessment Guidelines including:

- the key drivers;
- description and incremental forecast expenditure;
- demonstration that it satisfies the operating expenditure objectives and criteria as per NER 6.5.6 (a) and (c) respectively;
- justification of the change, including evidence, where applicable, that the change has been endorsed through our governance arrangements;
- cost build-up methodology;
- cost benefit or option analysis; and
- demonstration that the change is not double counted.

Table 21.3 provides a category summary of the step changes proposed for our 2015–20 operating expenditure and profiles the expenditure over the five year RCP. Subsequent paragraphs provide further explanation of the individual items in each category of step change. The values shown for each item represent the five year costs (June 2015 $) proposed to be included in our 2015–20 operating expenditure allowance. A summary of the proposed step changes and the relevant expenditure objectives/criteria is provided in Section 21.6.5.

21.6.1 Legal and regulatory obligations

The legal and regulatory framework for the electricity industry has been subject to an unprecedented level of change over recent years. These changes include but are not limited to:

- energy market reform;
- National Electricity Law and Rules amendments;
- National Energy Retail Law and Rules amendments;
- AER Better Regulation program Guidelines;
- increased focus on workplace health and safety laws and regulations; and
- changes to acceptable industry practice around asset inspections, maintenance and repair including those arising from community and legal review of industry practice towards mitigating bushfire risks.

Notwithstanding the multiplicity of these changes the industry is also faced in some cases with increased operating activity and costs to be able to maintain compliance with existing laws and regulations.

Table 21.4 provides an overview of this category of step change and the subsequent paragraphs provide further explanation of the individual items. Full details of each of these items are included in Section 1 of Attachment 21.13.

Table 21.3: Category summary of step changes for SCS operating expenditure for 2015–20

June 2015 ($m)	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Legal and regulatory	15.5	16.9	23.7	25.0	23.9	**105.0**
Capital program Impacts	10.3	16.3	16.7	13.8	12.5	**69.6**
Customer driven initiatives	10.7	9.0	8.2	7.1	6.6	**41.6**
Financing related matters	(0.6)	(0.2)	0.2	0.5	0.7	**0.6**
Total	**35.9**	**42.0**	**48.8**	**46.4**	**43.7**	**216.8**

Table 21.4: Legal and regulatory SCS step changes SCS 2015–20

June 2015 ($m)	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Asset inspections	8.5	8.9	8.9	8.9	6.9	**42.1**
Workplace health and safety	2.2	2.4	2.7	2.8	2.8	**12.9**
Energy laws and regulations	4.6	5.3	11.8	13.0	13.9	**48.6**
Environmental management	0.2	0.3	0.3	0.3	0.3	**1.4**
Total	**15.5**	**16.9**	**23.7**	**25.0**	**23.9**	**105.0**

Asset inspections

During the 2010–15 RCP SA Power Networks has increased the level and frequency of asset inspections in line with that approved by the AER in the 2010 Determination. This matter has been discussed in detail in Chapters 9 and 20. Notwithstanding this, the level of asset inspection work required in 2015–20 RCP to meet our requirements under our Safety Reliability Maintenance and Technical Management Plan (**SRMTMP**) is a step change above the expenditure incurred in the base year arising from:

- the need to undertake intrusive below ground inspection of 12,000 stobie poles per annum, previously considered "no access" because of surrounding bitumen, concrete and paving. Also the availability of new test equipment to cost-effectively assess the condition of underground cables. These two step changes are required to enable SA Power Networks to meet our regulatory obligations under our SRMTMP. The five year cost of this work is forecast at $26.5 million; and
- the move to an asset inspection frequency of five years for all assets in bushfire risk areas (**BFRA**) to align with newly established industry standards resulting from the Victorian Bushfire Safety Taskforce and subsequent legal proceedings. SA Power Networks is obligated under our jurisdictional legal and regulatory arrangements to apply prudent asset management practices having regard to good electricity industry practice[69]. Specifically, the Electricity Act and Electricity (General) Regulations require us to ensure that our infrastructure is safe and safely operated, and the SRMTMP defines how we do this. We will also increase the frequency and coverage of our thermo-graphic inspections to identify potential fire start faults in lines. The five year cost of moving some asset inspections in BFRA from a 10 year to a five year cycle is forecast to be $15.6 million (June 2015 $).

Workplace health and safety

We are proposing the following step change initiatives so that we can meet our duty of care for the well being and safety of our employees under the requirements of the *Workplace Health and Safety Act* and Regulations (2012):

- we have introduced in 2014–15 two person crews to undertake pre-bushfire season patrols. This initiative seeks to eliminate the travel-related risks that have the potential to arise from the previous one person patrol and is forecast to cost $2.8 million over the five years. This initiative also ensures that our staff comply with the requirements of the *SA Road Traffic Act (1961)*.
- increase in resource levels in our Network Operations centre (**NOC**) to ensure safe access is provided for our employees who work on our network 24/7. This item excludes any increases in NOC resources arising from increased capital spend in the 2015–20 RCP but addresses the safety risks indentified from the increased complexity of the NOC operations particularly during evening rosters. Forecast costs are $4.0 million over the next five years; and
- increase in fleet inspections and monitoring of our heavy vehicle fleet and our commercial vehicles to comply with more stringent obligations under SA traffic legislation. Forecast costs are $6.1 million (June 2015 $) over the next five years.

69 NER clause 5.2.1 provides that we must maintain and operate the network in accordance with good electricity industry practice and relevant Australian Standards.

Energy law and regulations

Changes to energy laws and regulations have given rise to the following additional operating costs which are not being incurred in the base year of 2013/14:

- new Regulatory Information Notice (**RIN**) requirements introduced in 2014 as part of the AER's Better Regulation program. The forecast expenditure over the five years is $9.2 million and represents increased costs incorporating a one-off vegetation management scoping cost and additional field and back office resources to capture and process the data and internal audit;
- under clause 90 of the National Energy Retail Rules SA Power Networks will be required from 1 July 2015 to notify customers four days in advance of planned outages less than 15 minutes in duration. SA Power Networks is currently exempt from this requirement to 30 June 2015. The forecast cost of this additional notification and the associated increased administration costs amount to $4.3 million over the five years, with an additional $6.2 million relating to ACS;
- under the NECF SA Power Networks will be required from 1 July 2015 to apply the AER's guideline for calculating customer contributions which is more complex with greater variability in costs to consumers. Accordingly, additional resources are 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 million (June 2015 $) over the 5 years; and
- the AEMC is currently considering a Rule change that will impact the structure of network pricing and it is expected to require DNSPs to be able to offer new cost reflective tariffs. Our Customer Engagement Program also identified that customers strongly support the introduction of capacity tariffs. We are proposing that such tariffs be progressively introduced from no later than 1 July 2017 with step change in operating costs to:
  - educate and support customers;
  - work with retailers in the transition to the new tariffs; and
  - develop and support new process capabilities in billing and related systems.

  We will also incur additional operating IT and Telecommunications expenditure associated with IT system upgrades necessary to accommodate more advanced metering in South Australia, including third-party smart meters. The forecast cost of this initiative is $33.8 million (June 2015 $) over the five years.

Environmental management

Environmental laws and regulations have undergone changes in recent years requiring increased activity to achieve compliance. Examples include:

- more stringent legislation and guidelines for the assessment and management of site contamination;
- a more stringent standard for the production and use of waste-derived fill (contaminated soil);
- changes to the Water Quality Policy (under the *Environment Protection Act 1993*);
- changes to the Native Vegetation Regulations; and
- additional risk assessment and mitigation measures required under the ARPANSA Electric and Magnetic Field (EMF) Guideline.

The forecast cost of achieving the additional compliance requirements is $1.4 million (June 2015 $) over the five years.

21.6.2 Impacts of proposed capital expenditure program for 2015–20

In accordance with clause S6.1.3 (1) of the NER, we are required, as part of the building block proposal, to identify and explain any significant interaction between the forecast capital expenditure and forecast operating expenditure programs for the 2015–20 RCP. Further, in relation to clauses 6.5.6(e)(7) and 6.5.7(e)(7) the AER must have regard to the operating and capital expenditure factors of 'the substitution possibilities between operating and capital expenditure' when assessing our forecast.

These clauses, therefore, require that two key issues be addressed with respect to our expenditure forecasts, being:

- whether a capital or operating expenditure alternative provides the most prudent and cost-effective solution to deliver the required services; and
- the operating expenditure impact of proposed capital expenditure.

In developing our Proposal we have given consideration to the relative costs, benefits, and risk characteristics of the options by which we can deliver SCS in the long term interests of consumers. The options selected, be they capital or operating in nature, are the most prudent and efficient of the alternatives available. Further, where capital expenditure solutions have been selected, we have given consideration to the operating expenditure implications and addressed these in our operating expenditure forecast. This has included consideration of the potential for a capex/opex tradeoff relating to the increased asset replacement program in the next RCP as outlined in Section 20.5. This capital program is aimed at managing our risk to acceptable levels in accordance with the SRMTMP and will not impact the level of operating maintenance undertaken during the next RCP. Table 21.4 summarises the capex/opex interaction.

The underlying rationale for the capital expenditure program proposed for the 2015–20 RCP is discussed in Chapters 9 to 16 and is further detailed in Chapter 20. This program requires a significant increase in associated operating expenditure when compared to the current RCP but avoids a significant further uplift in operating costs should the proposed capital expenditure not be undertaken. The step change operating expenditures shown in Table 21.5 are incremental to output growth applied, as these step changes are not directly related to an increase in output.

Table 21.4: Capex/Opex interaction step changes summary SCS 2015–20

June 2015 ($m)	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Opex uplift	10.0	16.1	18.2	18.7	19.9	**82.9**
Opex reduction	(0.5)	(1.5)	(3.2)	(6.7)	(9.3)	**(21.2)**
Capex/opex tradeoff	0.8	1.7	1.7	1.8	1.9	**7.9**
Total	**10.3**	**16.3**	**16.7**	**13.8**	**12.5**	**69.6**

Table 21.5: Capex/opex interaction step changes SCS 2015–20

June 2015 ($m)	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Information Technology (net)	6.6	11.2	11.3	8.1	6.7	**43.9**
Telecommunications	1.9	3.2	3.6	3.9	4.0	**16.6**
Data quality	1.0	0.8	0.7	0.7	0.7	**3.9**
Substation maintenance	0.4	0.5	0.5	0.5	0.5	**2.4**
Condition monitoring	0.2	0.4	0.4	0.4	0.4	**1.8**
Flexible load management	0.2	0.2	0.2	0.2	0.2	**1.0**
Total	**10.3**	**16.3**	**16.7**	**13.8**	**12.5**	**69.6**

The following paragraphs provide a summary explanation of the above step changes with full details of each item included in Section 2 of Attachment 21.13.

Information Technology (net opex uplift) — Chapter 16 outlines the proposals to ensure we have the capabilities to deliver on our regulatory obligations and provide the level of customer service our customers are seeking. Section 20.8.1 provides further details on the proposed IT capital investment program. The program requires additional operating expenditure for the ongoing maintenance and support of these systems. IT operating expenditure is forecast to increase by a net $43.9 million over the five year period. This comprises an uplift of $65.1 million, offset by forecast benefits of $21.2 million (being cost reduction within the RCP) to be realised across the entire business from the program investment. The proposed IT capital investment avoids an additional $36.8 million in costs (predominantly labour costs associated with alternative manual options) that would be required to meet legal, regulatory, customer and business requirements if these systems were not developed and implemented. Refer Attachment 20.42 for further information.

Telecommunications — mobile radio network (capex/opex trade-off) — Migration of our mobile radio network capacity to the SA Government network has been assessed as the most prudent and efficient solution to replacing our existing mobile radio network which has exceeded equipment life expectancy. The migration to the new system and decommissioning of the old system will occur in 2016/2017. The total step change adjustment, incremental to the current maintenance cost, for the 2015–20 RCP is an expenditure increase of $7.9 million (June 2015 $).

Telecommunications — carrier costs and radio licensing — The increased number of intelligent devices being installed in the network during the next RCP, (as outlined in Chapter 20, to progressively deliver a smarter grid, substation control and quality of supply (**QoS**) monitoring means) there is a requirement to manage and transport the additional data presented. This will require an uplift in costs associated with our telecommunication 3G and 4G services, inter office and depot data carriage and additional private radio services in regional areas requiring licensing. The total step change adjustment over the next five year period is an expenditure increase of $3.0 million (June 2015 $).

Telecommunications — planning and control — We currently operate a Telecommunications Network Operations Centre (**TNOC**) to manage and maintain our complex telecommunications network across the State. With the increased volume of work expected in 2015–20 it will be necessary to engage additional resources to enable the efficient operation of the TNOC by separating the monitor and control function from the field restoration tasks. In addition, extra resources are required in the planning group to enable effective asset management of the telecommunications network and to manage the increased security risks of unauthorised access to the network. The total step change adjustment over the next five year period is an expenditure increase of $5.7 million (June 2015 $).

Data quality — Implementation of the Customer Data Quality Plan to improve customer data quality. This involves moving to a holistic, productivity improvement-focussed data management system, building on the investment we have made to date in people and technology. It will add new capabilities for data cleansing and enrichment, and increase coverage to all components of the customer data domain. The total step change adjustment over the next five year period is an expenditure increase of $3.9 million (June 2015 $).

Substation maintenance — disconnectors — Incremental costs required to undertake the live-line maintenance of substation disconnectors in lieu of maintenance in a de-energised state. De-energised maintenance is proving difficult to achieve as it causes high costs and disruption to customers. The total step change adjustment over the next five year period is an expenditure increase of $2.4 million (June 2015 $).

Condition monitoring and network planning — The asset management strategic direction is detailed in AMP 3.01.01 Condition Monitoring and Life Assessment Methodology. The objective of this strategy is to further implement a condition/performance risk based replacement strategy rather than relying principally on age as the measure of remaining asset life. To achieve this, we will purchase and implement condition monitoring equipment, programs and tools to enable the most economically efficient management of critical assets while meeting our regulatory obligations. To implement this strategy additional asset management (office based) and field test personnel are required at an additional cost over the next five year period of $1.8 million (June 2015 $).

Flexible load management — The Flexible Load Strategy (**FLS**) is concerned with the future use of controllable load to manage voltage variations in the low-voltage network arising from high penetration of solar and other embedded generation, and to reduce peak demand. The impacts on voltage levels arising from embedded generation within our network have been discussed in Chapter 13. One of the greatest opportunities to manage this issue in future is through more active use of flexible loads. Flexible loads are those electrical loads that customers may be able to shift to different times without material loss of amenity. There are two new opex cost components arising from the FLS:

- system administration and operating costs for a new database to track installation of AS4755-compliant devices, and to support dynamic load control trials, estimated at 1 FTE; and
- an advertising campaign to promote the take-up of products such as pool pumps, hot water systems, battery storage systems and electric vehicle chargers that have features that enable load to be controlled dynamically.

The total step change adjustment over the next five year period is an expenditure increase of $1.0 million (June 2015 $).

21.6.3 Customer-driven initiatives and changing community expectations

As discussed previously, the electricity industry faces unprecedented change over the next 10 to 15 years. We are guided by the long-term interests of consumers when making decisions including 'the extent to which our operating expenditure forecast includes expenditure to address the concerns of electricity customers as identified by us in the course of our engagement with electricity customers'. Refer NER 6.5.6(e)(5A).

As outlined in Chapter 6 our comprehensive TalkingPower program has specifically identified vegetation management, customer service and community safety as key focus areas of customers.

Table 21.6 summarises the expenditure on the programs that address these issues, and represent costs that a prudent operator in these circumstances would incur in meeting the operating expenditure objectives under the NER.

The following paragraphs provide a summary explanation of these step changes with full details of each item included in Section 3 of Attachment 21.13.

Vegetation management

SA Power Networks has responded to a clear mandate arising from our Customer Engagement Program that action should be taken in the next RCP to develop a more sustainable long term approach and to move away from the one size fits all prescriptive program currently operating. The development of the longer term approach was undertaken in a highly collaborative manner and has strong support from the Local Government Association (**LGA**), our Arborist Reference Group and is underpinned by the specific Willingness to Pay research we have undertaken. Key initiatives include:

- moving to a two year inspection and cut cycle in metropolitan Adelaide and regional townships. Forecast cost over the five years is $13.5 million (June 2015 $);
- undertaking tree removal and replacement programs in both BFRA and non-BFRA (**NBFRA**) to remove inappropriate, fast growing or large trees. This will be done in consultation with local councils and communities considering a range of environmental, legislative and community factors. The forecast cost is $15.3 million (BFRA $9.2 million and NBFRA $6.1 million) over the next five year period and is net of reduced cutting costs of $10.5 million (June 2015 $) from this item and from targeted undergrounding of power lines as discussed in Chapter 11;
- engagement of a number of arborists to provide expert advice and input into advanced tree trimming practices. The forecast costs are $1.9 million (June 2015 $) over the next five year period; and
- community engagement and consultation in support of the long term vegetation management strategy will require the development of a protocol of how we work with councils and targeted media campaigns to promote the planting of appropriate species near power lines. This work is forecast to cost $1.2 million (June 2015 $) over the next five year period.

Customer service

As discussed in Section 7.6 we have established a Customer Service Strategy 2014–2020. This has been developed 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. The new strategy identifies a set of strategic focus areas that meet emerging customer needs, including to:

- be recognised as a national leader in the delivery of safe, reliable and quality power;
- manage and maintain a cost effective and relevant network that caters for a diverse range of electricity consumers;
- 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.

Table 21.6: Customer driven and changing community expectation SCS step changes 2015–20

June 2015 ($m)	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Vegetation management	8.0	7.1	6.4	5.6	4.8	**31.9**
Customer services	1.0	0.7	1.0	0.6	1.0	**4.3**
Community safety	1.7	1.2	0.8	0.9	0.8	**5.4**
Total	**10.7**	**9.0**	**8.2**	**7.1**	**6.6**	**41.6**

A number of key initiatives are being developed during 2014/15 and will be progressively implemented during the 2015–20 RCP including:

- a program to educate customers on the electricity industry so that they better understand who we are and what we do. With this enhanced customer awareness, knowledge and trust, communicating some of the more complex messages such as Demand Side Participation will be improved. The total step change adjustment over the next five year period is an expenditure increase of $1.7 million (June 2015 $);
- implement a tailored digital advertising strategy to support the launch and communication of new self-service options and provide materials to industry groups, community groups and community information sources such as libraries and community centres. The total step change adjustment over the next five year period is an expenditure increase of $1.0 million (June 2015 $); and
- introduction for the first time, of a dedicated customer experience improvement team. Members of this team will have the responsibility for developing customer service capability across the organisation and for ensuring priority customer improvement initiatives are deployed in the field across the organisation. In the initial phase this dedicated team of professionals will develop a customer aligned whole-of-business framework to initiate, develop, implement and measure customer experience improvement initiatives. With greater maturity, the team's focus will be to ensure their account teams' efforts align with the plans and activities of other teams. This is consistent with ensuring the internal business alignment with the Customer Service Strategy and the corporate strategy. Greater alignment and cohesiveness will be more cost-efficient, targeting the right measures and avoiding duplication. The total step change adjustment over the next five year period is an expenditure increase of $1.6 million (June 2015 $).

Community safety

Our comprehensive TalkingPower engagement program, regular customer surveys and day to day interactions with customers have provided us with direction in the development of our 2014–20 Communications Plan. The plan contains a comprehensive, but prudent, advertising and support program to address a significant number of the consumer insights generated from TalkingPower.

The forecast expenditure is consistent with comments made previously by the AER (on page 225 of 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 opex objectives, in particular, clauses 6.5.6 (2), (3) and (4) of the NER."*

Key safety-related communication initiatives include:

- **Bushfire —** We are proposing a media campaign targeted in the summer months (November to January) to better educate our customers about the dangers and implications of these potential events, as well as having better coverage during high risk bushfire days in respect to power lines and outages. To date we have taken a fairly low-key approach with bushfire awareness and advertising, centred on South Australia's high bushfire risk areas. The approach has been extremely reactive based on catastrophic fire danger days only. Through our customer engagement work we have come to understand we have a greater number of customer groups we need to be talking to as:
  - many people live in NBFRAs but are served by lines going through high-BFRA (**HBFRAs**);
  - more people are travelling to and through BFRAs, and staying in unfamiliar surroundings;
  - businesses need greater levels of communication than currently provided; and
  - people that live in metropolitan Adelaide need additional communication about heatwaves.

  The total step change adjustment over the next five year period is an expenditure increase of $2.6 million (June 2015 $).

- **Extreme weather —** As discussed in Chapter 10 we are already experiencing increasing intensity and frequency of extreme weather events in South Australia. In February 2014 we experienced one of the most significant storms to hit the network in recent history, with some 90,000 affected customers being left without power for more than twelve hours. Fortunately no-one was injured as a result of the extensively damaged network.

  We are proposing a 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. This will focus on having more responsive advertisements that can be placed into the media within 24 hours to prepare customers for possible outages. The media activity will be focussed more on metropolitan areas rather than regional, given the concentration of population means that safety around fallen power lines is more of a concern in these locations. The total step change adjustment over the next five year period is an expenditure increase of $1.9 million (June 2015 $).

- **Farmers and sailors —** Safety remains our number one priority with this group, particularly as we are still seeing farming accidents occur. Farmers are using bigger machinery which is more likely to come into contact with power lines, they are working longer hours, and they are more reliant on GPS tracking which could mean they miss seeing power lines. Similarly, recreational sailors manoeuvring yachts with tall masts can come into contact with power lines. The advertising program will be targeted through particular trade press and digital channels. This will be supplemented by low-cost public relations activities with sailing clubs, for example. Regional radio is an important channel to reach farmers 'at work', while regional television can be used to target their families. The total step change adjustment over the next five year period is an expenditure increase of $0.9 million (June 2015 $).

21.6.4
Financing related operating expenditures

The expenditure categories of insurance premiums and superannuation have been prepared on a zero-based basis. The movements from the 2013/14 base year have been included as part of the base-step-trend approach. Table 21.7 outlines these step change expenditures for the 2015–20 period with the subsequent paragraphs providing a summary explanation of the individual items. Full supporting details are contained in Section 4 of Attachment 21.13.

Insurance premiums

We purchase insurance as a mechanism for the transfer of costs relating to material risks for which insurance is available on cost effective terms. The limits of liability are based upon assessment (by consultants where relevant) of the maximum likely cost of a realistic event. Except where market forces dictate otherwise, deductible levels are set such that we maintain the risk for losses which are of a relatively high frequency and low quantum.

Premium levels are impacted by our risk profile (for example as determined by our activities and claims history), and by insurance market factors outside our control. These include the impact of global natural disasters and other claims experience, and insurer competition, capacity and capital requirements. In view of the number and nature of price-influencing factors, which in combination are unique to insurance, industry expert Aon Risk Services Australia Limited ("**Aon**") was engaged to independently forecast our insurance premiums for the 2015–20 RCP. Aon is the insurance broker and risk management consultant to 65% of Australian electricity distribution businesses, is the leading Australian provider in this sector for Regulatory Proposal consultancy services, and has detailed knowledge of our risk profile.

To forecast premiums, Aon estimated exposure growth and premium rate growth for the forecast period and applied these growth rates to our premiums for the base year. Aon accounted for the impact of features particular to our major programs and their market context. For example, insurers' diminishing appetite for bushfire risk, the prevalence of bushfires and significant bushfire claims, and our low premium relative to entities with similar risk profiles, were considered in forecasting the liability policy premiums. With regard to property insurance premium forecasts, the assessment encompassed a range of factors including the highly competitive property insurance market. The Insurance Premium Forecast by Aon is provided as Section 4.1 of Attachment 21.1 to this Proposal.

The total step change adjustment over the next five year period is an expenditure increase of $3.0 million (June 2015 $).

Superannuation

Superannuation expenditure relates to the operating allocation of the superannuation contributions that we are required to make to the Electricity Industry Superannuation Scheme (**EISS**) and other superannuation schemes in the 2015–20 RCP. The EISS actuary, in conjunction with the EISS Board, independently sets the required employer contributions to ensure that the EISS is appropriately funded, based on assumptions reflecting their actuarial standards.

A significant proportion of our employees within the EISS have defined retirement benefits — entitlements that must be fully funded. The EISS actuary is currently undertaking a three yearly review of the required contribution rates. New contribution rates will apply from 1 January 2015 for employees within the various subdivisions of the EISS. As the new contribution rates to apply from 1 January 2015 are not known at the time of this submission, the contribution rates that currently apply have been used to calculate forecast superannuation contributions. The negative adjustments over the five year period, as shown in Table 21.7, reflects the lower contributions that commenced part way through the 2013/14 base year. Our Revised Proposal will incorporate the new contribution rates as determined by the EISS actuary and Board.

Table 21.7: Insurance premiums and superannuation SCS step changes 2015–20

June 2015 ($m)	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Insurance premiums	0.3	0.4	0.6	0.8	0.9	**3.0**
Superannuation*	(0.9)	(0.6)	(0.4)	(0.3)	(0.2)	**(2.4)**
Total	**(0.6)**	**(0.2)**	**0.2**	**0.5**	**0.7**	**0.6**

*An actuarial review is currently being undertaken. The outcome of this review will be included within the Revised Proposal.

Table 21.8: Summary of SCS step changes and objectives/criteria (NER clause 6.5.6)

	June 2015 $m	Legal and regulatory (a)(2)	Customer driven (a)(1)	Capex related (a)(1)	Service Standards (a)(3) & (4)
Asset inspections	42.1	✓			
Workplace health and safety	12.9	✓			
Energy laws and regulations	48.6	✓	✓		
Environment	1.4	✓			
Information Technology	43.9	✓	✓	✓	
Telecommunications	16.6	✓		✓	✓
Data quality	3.9	✓	✓		
Substation maintenance	2.4				✓
Condition monitoring	1.8	✓			✓
Flexible load management	1.0	✓	✓		
Vegetation management	31.9	✓	✓		
Customer services	4.3		✓		
Community safety communications	5.4	✓	✓		
Insurance premiums	3.0	✓			
Superannuation	(2.4)	✓			
Total	**216.8**				

21.6.5
Summary of step changes in operating expenditures and relevant objectives/criteria

Table 21.8 provides a summary of the key items of step change to operating expenditure for the 2015–20 RCP and indicates the relevant expenditure objective or expenditure criteria related to the item.

21.7

Rate of change

In the AER's Expenditure Forecast Assessment Guideline (Section 4.2), the AER advises of its intention to assess a DNSP's forecast operating expenditure by applying an 'annual rate of change', where the annual rate of change in operating expenditure for each year (t) is:

$$\textit{Rate of change}_t = \textit{output growth}_t + \textit{real price growth}_t - \textit{productivity growth}_t$$

We have adopted in this Proposal a similar scale escalation model to the one approved by the AER in our 2010 determination as the basis to estimate output growth for the 2015–20 RCP forecast. The derivation of the output growth is described in Section 21.8 below.

Real price growth has been forecast for real changes in input costs for the 2015–20 RCP, specifically labour, materials, services and land. The forecasts of input cost escalation rates is described in Section 21.9 below.

Productivity growth is considered in Section 21.10 below.

Individually and collectively the rate of change components incorporated in our expenditure forecast are consistent with the NER requirements, in that they reasonably reflect a realistic expectation of the cost inputs required to achieve the operating and capital expenditure objectives and therefore must be accepted by the AER in accordance with NER clauses 6.5.6(c) and 6.5.7(c).

21.8

Output growth

This section considers the impact of output growth on forecast expenditures.

The Explanatory Statement to the Expenditure Forecast Assessment Guideline recognises that "*increased demand for NSPs' outputs may require them to expand their networks. It is reasonable that an efficient NSP will require more inputs, and thus greater opex, to deliver more output.*"[70]

In forecasting the output growth that will apply to its operating expenditure for the 2015–20 RCP, SA Power Networks has determined that its operating expenditure is linked to certain high-level factors that drive the volume of its operating and maintenance activities. SA Power Networks' operating expenditure forecasts incorporate economies of scale derived for each of these factors.

For the 2010–15 RCP, the AER accepted SA Power Networks' methodology of applying the following four key escalators that drive output growth:

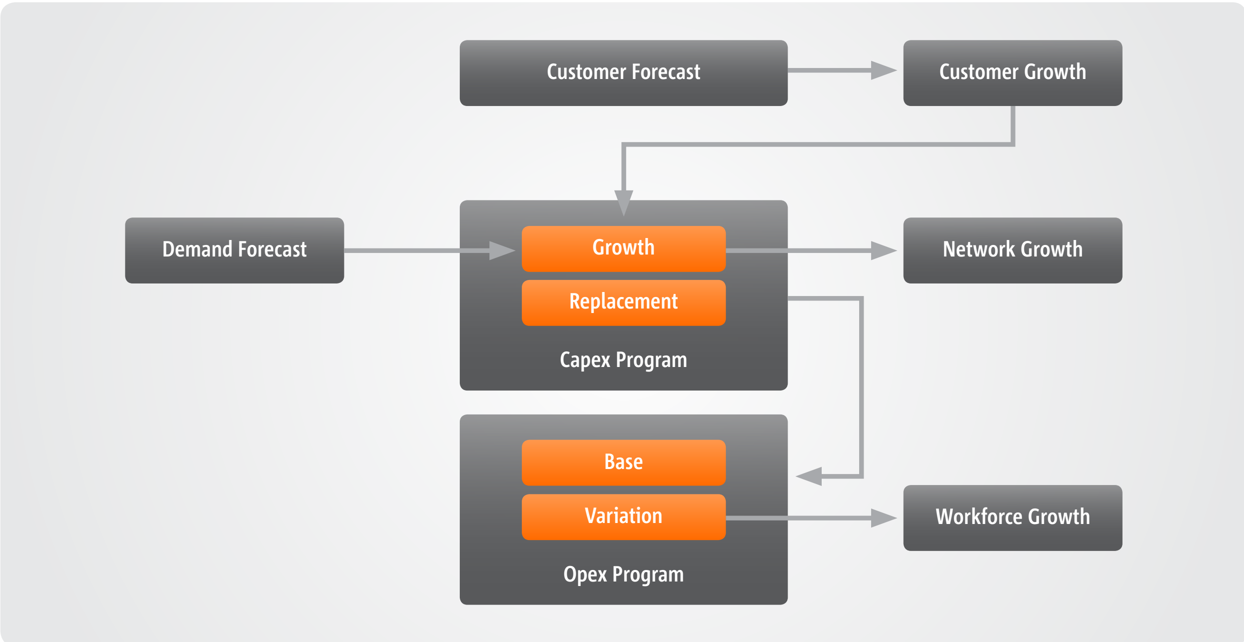
- **Network growth:** growth in the size of the distribution network;
- **Customer growth:** growth in customer numbers;
- **Work volume:** changes in the volume of capital and maintenance work taking place on the network; and
- **Workforce size:** changes in the size of the workforce.

Since that determination the AER has introduced the Expenditure Forecast Assessment Guideline and collected historical data for benchmarking purposes. Consistent with the Guideline's emphasis on trend in the build-up and assessment of costs for operating expenditure, SA Power Networks has applied data provided in the recent Economic Benchmarking and Category Analysis RINs to determine its output growth for the 2015–20 RCP. Historical data is free from any potential forecasting error, reasonably reflects the expected output growth in the future and is consistent with more recent distribution determinations where the AER has demonstrated a preference for the use of historical data to estimate growth factors.[71]

Consequently work volume has not been included as a growth escalator for the 2015–20 RCP, in part due to the absence of a historical work volume data series. Activities previously escalated by work volume have been reclassified accordingly. In general, network and customer growth escalators have been applied to operational and customer service activities, and workforce size growth escalation has been applied primarily to back-office and support functions, for example, training and information and communication technology services. A full list of escalators, including changes from the 2010–15 RCP, is contained in the Scale Escalation model at Attachment 21.4.

The drivers of output growth for the 2015–20 RCP are depicted in Figure 21.5.

Figure 21.5: Drivers of output growth



SOURCE: SA POWER NETWORKS ANALYSIS 2014

70 AER, Explanatory Statement to Expenditure Forecast Assessment Guideline, November 2013, p. 61.

71 For example AER, Victorian distribution determination final decision 2011–2015, October 2010, p. 304.

The above escalators are closely related, and we have taken care to ensure that any double counting has been eliminated. Economies of scale have been applied to recognise that costs do not generally increase in direct proportion to scale growth. The economies of scale factors are consistent with those accepted for SA Power Networks' 2010 Determination. The economies of scale applied for each activity are also contained in the Scale Escalation Model at Attachment 21.4.

We propose that the application of the three key escalators reflects a realistic expectation of the cost inputs required to achieve the operating expenditure objectives.[72]

The impact of these escalators upon our operating expenditure forecast for the 2015–20 RCP is summarised below in Table 21.9.

Derivation of the growth escalators
Growth in SA Power Networks' electricity distribution network is forecast to average 1.59% per annum. This is calculated as the historical average percentage increase in SA Power Networks' distribution line length, and distribution transformer and substation installed capacity, weighted by their depreciated capital value, derived from information contained in the Economic Benchmarking RIN.

In its final determination for SA Power Networks' 2010–15 RCP, the AER asserted that a material proportion of emergency response activities were driven by asset failure arising from poor condition, rather than from external factors such as weather-related damage. The AER asserted that asset replacement capital expenditure and maintenance should directly reduce the level of emergency response operating expenditure and considered it reasonable that the network growth escalator for this activity be reduced for interruptions arising due to equipment failure. Consistent with this approach, SA Power Networks has reduced the economy of scale factor for emergency response by 21% to reflect the percentage of breakdowns caused by equipment failure since July 2008. The percentage of breakdowns from equipment failure has been extracted from interruptions data contained in the Category Analysis RIN.

Operating expenditure associated with the services which we provide directly to customers — such as call centre services — is primarily driven by change in the number of our customers. Customer growth escalation of 1.34% per annum has been applied based on the historical average increase in residential customers, extracted from data contained in the Economic Benchmarking RIN.

The size of our workforce, incorporating both employees and supplementary labour contractors, will act as another key driver of our operating expenditures during the 2015–20 RCP. Forecast growth escalation of 4.47% per annum has been applied based on the historical increase in average staffing levels contained in the Category Analysis benchmarking data.

21.9

Real price growth

The second part of the rate of change formula relates to real price growth. CPI-X type regulation provides the DNSP with some level of compensation for increases in the costs of its inputs, however many of the costs faced by electricity utilities do not increase in ways that are reflective of the CPI basket of goods.

SA Power Networks has considered the broad categories of cost underpinning expenditure forecasts that will increase at a rate different to CPI over the 2015–20 RCP. These categories are summarised below:

- **Labour:** costs associated with employees and supplementary labour contractors in delivering SCS;
- **Contracted construction and labour services:** services acquired in order to deliver SCS, for example, electrical construction, civil works, traffic management and vegetation management;
- **Materials:** costs of distribution equipment such as conductors, cables, insulators, circuit breakers, transformers and SCADA equipment in addition to materials for the production of poles and other items of equipment such as vehicles, plant and tools; and
- **Land:** costs associated with the purchase and management of land and easements used in operating the distribution system.

Table 21.9: Impact of output growth on SA Power Networks' forecast operating expenditure — SCS 2015–20

June 2015 ($m)	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Network growth	1.9	3.8	5.8	7.8	9.6	**28.9**
Customer growth	0.5	1.0	1.5	2.0	2.6	**7.6**
Workforce size	0.6	1.3	2.1	2.8	3.4	**10.2**
Total	**3.0**	**6.1**	**9.4**	**12.6**	**15.6**	**46.7**

72 NER, clause 6.5.6(c)(3)

Independent expert consultants have been utilised to provide forecasts of real growth rates in the costs of these broad expenditure categories. The AER is required to accept these forecasts if it is satisfied they reasonably reflect the principles of prudency and efficiency and are, "... a realistic expectation of the ... cost inputs required to achieve the [operating and capital] expenditure objectives."[73]

The forecasts provided by these consultants have been applied to the relevant areas within our expenditure model, and have also been applied uniformly to both operating and capital expenditure.

21.9.1 Labour

SA Power Networks has identified labour as one area of cost that will experience higher than CPI cost increases in the 2015–20 RCP. As such, we engaged expert consultants to provide forecast escalation rates to be applied to both operating and capital expenditure forecasts. In particular, SA Power Networks has instructed Frontier Economics Group (**Frontier Economics**) to develop an escalation rate approach that provides a realistic forecast of labour costs.

To forecast real labour cost escalation rates, the AER has recently accepted relevant Enterprise Bargaining Agreement (**EBA**) outcomes current at the time of their determination through to their expiry, then, for the remainder of the RCP, has reverted to forecasts based on the Wage Price Index (**WPI**) for the Electricity, Gas, Water and Waste Services (**EGWWS**) industry for the appropriate state. Preparation of these forecasts by third party consultants is required on behalf of the AER and the relevant DNSP, as the Australian Bureau of Statistics (**ABS**) does not provide forecasts of the WPI for the EGWWS industry in South Australia.

However, there are significant limitations to this approach and SA Power Networks engaged Frontier Economics to develop an alternative method to forecast a real labour escalation rate that improves upon these limitations. These limitations are discussed in brief below. See Attachment 20.2 for their full report.

- **Cost-reflectivity:** The EGWWS WPI is not representative of the labour costs of an electricity distribution business.
- **Availability of data:** Data for the South Australian EGWWS WPI is not released by the ABS due to its small sample size. As a result, forecasts of the EGWWS WPI for SA are based on imputed values.
- **Discontinuity:** Splicing together current EBA outcomes with consultant's forecasts (eg Deloitte Access Economics (**DAE**) and BIS Shrapnel) is likely to lead to a large, unwarranted discontinuity in the forecast of labour costs over the RCP.

In line with the Explanatory Statement to the AER's Expenditure Forecast Assessment Guideline, SA Power Networks and Frontier Economics have adopted an approach based on trend analysis to forecast the real labour cost escalation rate. The AER comments in the Explanatory Statement (page 83):

"We consider trend analysis provides a reasonably good technique for estimating future expenditure requirements where historical expenditure has similar drivers to future expenditure and these drivers can be forecast."[74]

Historical labour cost expenditure has consistently been driven by SA Power Networks' EBA outcome and these agreements will continue to drive future labour costs. Consequently, Frontier Economics has developed forecasts based on an average of EBA outcomes of a comparator group of similar companies. Frontier Economics considers this forecasting approach improves upon the AER's recent approach in the following ways:

- **Cost-reflectivity:** EBA outcomes are significantly more reflective of the true labour escalation rates of individual DNSPs;
- **Availability of data:** Actual EBA data is readily available to the public;
- **Discontinuity:** An approach based on EBA outcomes throughout the RCP (ie current EBA outcomes then forecast EBA outcomes), is unlikely to suffer from the discontinuity caused by using two different methodologies, and historical EBAs of DNSPs have been relatively stable; and
- **Adherence to forecasting principles:** The approach is simple and transparent and the AER and stakeholders have access to the necessary information in order to assess the validity and accuracy of the forecasting approach.

The AER has raised the concern that forecasts based on EBAs could remove the incentive for NSPs to negotiate efficient outcomes. Frontier Economics has determined that SA Power Networks' EBAs are negotiated on an arm's length and commercial basis and recommends basing the forecast on the average EBA outcomes of a suitable comparator group of NSPs, which no single DNSP can influence. As SA Power Networks cannot influence the forecast and combined with the driver of incentive-based regulation, there is a clear incentive to continue to achieve the most efficient EBA outcomes over time, in turn driving efficiencies across the entire comparator group, thus benefiting customers over time.

SA Power Networks has incorporated in its Proposal Frontier Economics' forecast based on a five year extrapolation of average EBA outcomes for the comparator group. These are detailed in Table 21.12. For further information regarding Frontier Economics' approach, please refer to the full report in Attachment 20.2.

73 Clauses 6.5.6 (c) and 6.5.7 (c) of the NER.

74 AER Explanatory Statement — Expenditure Forecast Assessment Guidelines, p. 83.

Table 21.12: SA Power Networks proposed labour cost escalation

	2014/15–2016/17 EBA		Frontier Economics' forecast			Total
	2015/16	2016/17	2017/18	2018/19	2019/20	
Nominal %	4.50%	4.50%	4.37%	4.37%	4.37%	
Forecast CPI %	2.55%	2.55%	2.55%	2.55%	2.55%	
Real %	1.66%	1.66%	1.77%	1.77%	1.77%	
Labour escalation June 2015 ($m)	2.0	4.1	6.8	9.5	12.0	**34.4**

21.9.2 Contracted construction and labour services

In its 2015–20 RCP, SA Power Networks will engage contracted service providers to deliver some of the proposed operating and capital expenditure programs. Examples of these services include electrical construction, civil works and traffic management. Of the available ABS categories for capturing historical costs, the construction sector most accurately reflects the true costs SA Power Networks incurs in relation to contracted construction and labour services.

SA Power Networks has engaged BIS Shrapnel to prepare forecasts of the South Australian Construction sector WPI and proposes an average of these forecasts from BIS Shrapnel and DAE as the Contracted Construction and Labour Services escalation rate. The forecasts delivered by BIS Shrapnel are detailed in Table 21.13. This approach is proposed to the AER following its recent SP AusNet transmission determination and in the absence of an alternative approach to forecasting these costs.

In SP AusNet's 2014–2017 transmission Determination process, the AER adopted an average of BIS Shrapnel and DAE forecasts of the Victorian WPI of the construction industry. The AER stated it believed that an average of the two forecasts was more reliable than simply adopting a single forecast (either BIS Shrapnel or DAE)[75]. Other analysis has also been conducted to demonstrate that an average of forecasts is likely to be a superior approach compared to using one individual forecast, due to lower forecasting error.[76]

21.9.3 Materials

SA Power Networks' materials costs relate primarily to items of equipment utilised in the construction and maintenance of the distribution network. It does, however, also encompass other equipment such as vehicles, clothing and plant and tools utilised by personnel in undertaking work on the network.

In the case of materials, SA Power Networks has engaged Competition Economists Group (**CEG**) and Jacobs (**Jacobs**, formerly SKM) to develop forecasts of the real cost changes likely to be observed in the next RCP, utilising a methodology that has been previously accepted by the AER in price determinations.

This methodology determines real price escalation of materials by considering:
- the mix of components (for example, transformers, circuit breakers and conductors) utilised in constructing and/or maintaining the distribution network;
- an estimate of the weightings of commodities influencing the cost of those components (for example, the cost of transformers is influenced in varying proportions by the cost of copper, iron ore material, insulating oil and structural steel); and
- the forecast real cost increases of those commodities.

For items not impacted by commodity price movements, forecast CPI growth is assumed.

Table 21.13: Forecast real% change in construction WPI in South Australia

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
SA Construction WPI %	0.50%	0.90%	1.10%	1.40%	1.80%	
Construction & labour services escalation June 2015 ($m)	0.8	2.2	4.1	6.4	9.3	**22.7**

75 *Final Decision SP AusNet Transmission Determination 2014–15 to 2016–17,* Australian Energy Regulator, http://www.aer.gov.au/sites/default/files/AER%20final%20decision%20for%20SP%20AusNet%27s%202014–17%20regulatory%20control%20period%20-%2031%20January%202014.pdf, January 2014, p. 69.

76 *Recommendations for methodology for forecasting WPI,* Professor Jeff Borland, http://www.aer.gov.au/sites/default/files/Attachment%206.8%20Response%20to%20Draft%20Decision%20-%20Recommendations%20for%20Methodology%20for%20Forecasting%20WPI%20%28Professor%20Borland%29_0.pdf, October 2012, p. 3.

The methodology applied is characterised by a high degree of transparency. Additionally, CEG has reviewed their past performance of forecasting materials cost escalation to conclude that their methodology contains no systematic bias. Consequently we consider that CEG's forecasting methodology provides the most appropriate forecast of materials escalation for the next RCP.

CEG has developed commodity escalation based on futures prices and movements in foreign exchange rates where applicable, or forecasts available from Consensus Economics. In the case of crude oil an escalation factor based on constant real US prices has been applied, based on a recent AER decision for the Victorian gas distribution businesses. CEG's full report is included as Attachment 20.3.

Jacobs has converted CEG's real escalators for raw commodities to real materials escalation rates using weightings determined in their established cost escalation model. The weightings are based on Jacob's most recent study of distribution and transmission price and contract information. A copy of Jacob's full report is included as Attachment 20.4.

The methodology above has been utilised to develop a weighted average escalator to be applied across all materials costs. The resultant forecasts are shown in Table 21.14.

21.9.4 Land

SA Power Networks has identified that, based on long-term historical trends, South Australian site values continue to increase at a rate above CPI. There are a number of costs borne by SA Power Networks that directly relate to the site value of the properties owned, hence it is appropriate for SA Power Networks to apply a real land cost escalation rate to these costs.

Maloney Field Services (**MFS**) was engaged by SA Power Networks to develop this escalation rate based on unimproved land values in South Australia. Consistent with the methodology accepted by the AER in its ElectraNet 2013–2018 Determination, MFS has used long-term ABS data to develop its escalation rate. The particular index used by MFS is the 'Total Land' factor and full details of the methodology employed are contained in their report in Attachment 20.5 and is the most realistic forecast of land escalation available.

The proposed escalation rates are detailed in Table 21.15 below.

Based on MFS' independent forecasts, SA Power Networks proposes that the application of the MFS escalators reflects a realistic expectation of the cost inputs required to achieve the operating and capital expenditure objectives. The following tables summarises the impact of these escalators on our operating expenditure forecast for the 2015–20 RCP.

Table 21.14: Proposed materials escalation, real

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Materials escalation %	0.71%	0.12%	0.01%	-0.02%	0.02%	-
Materials escalation June 2015 ($m)	0.0	0.0	0.0	0.0	0.0	**0.1**

Table 21.15: Proposed land cost escalation, real

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Total land %	5.96%	5.96%	5.96%	5.96%	5.96%	-
Land escalation June 2015 ($m)	0.3	0.5	0.8	1.1	1.5	**4.2**

21.10

Productivity

As referred to in Section 21.7 above, the AER has introduced the rate of change formula for its assessment of operating expenditures. The formula includes a productivity adjustment factor, which the Explanatory Statement to the Expenditure Forecast Assessment Guideline implies as comprising:

- an individual adjustment for DNSPs to 'catch up' to the efficient frontier; and
- an industry adjustment for the expected shift in the industry's efficient frontier.

As outlined in Section 4.2, SA Power Networks does not believe that the AER's benchmarking is sufficiently robust to be applied deterministically.

Notwithstanding this, SA Power Networks has worked with Huegin Consulting to conduct preliminary modelling to determine SA Power Networks' relative efficiency. Multilateral Total Factor Productivity (**MTFP**) modelling results, based on the AER's preferred model specification and methodology, demonstrate that SA Power Networks sits at the efficient frontier. At the efficient frontier, a 'catch up' factor is not applicable, consequently no individual adjustment is required to SA Power Networks' efficient base year costs.

As well as being benchmarked as a leader in economic efficiency, SA Power Networks has demonstrated that over the current RCP it has responded to the incentives within the Efficiency Benefit Sharing Scheme (**EBSS**) with accrued outperformance against allowances, thus sharing benefits with customers.

SA Power Networks notes that the MTFP results for the industry have been declining over the benchmark period. This should not be inferred as evidence of declining efficiency. For SA Power Networks, since 2010 we have identified a number of exogenous factors that have negatively impacted on the MTFP modelled outcomes, including:

- Vegetation management: Vegetation management costs have doubled with the breaking of the 'millennium drought' in 2010 and the subsequent rapid growth in vegetation and resulting clearance infringements around power lines. These additional input costs have been and continue to be incurred to ensure community safety but do not increase MTFP outputs; and
- Reliability Guaranteed Service Level (**GSL**) payments: During the current RCP, there has been a significant increase in the severity of severe weather events (storms, lightning and high winds). The payments made to customers for the inconvenience of loss of supply are nearly triple the level of the five years of the previous RCP. The effect of these severe weather events increases the input costs in the MTFP analysis and also has a negative impact on outputs through increased customer interruptions.

As stated in Section 4.2, the AER's inaugural Annual Benchmarking Report will not be released until November 2014 and as a consequence its findings have not been available for assessment nor taken into account in this Proposal. In view of this and based on the maturity of the AER's models, SA Power Networks does not believe that it is appropriate for the AER to apply either an individual or industry productivity adjustment in the rate of change formula for the 2015–20 RCP.

Nevertheless, customers can be assured that efficiency improvements have been considered throughout the development of SA Power Networks' Proposal, and forecast productivity gains have been incorporated where possible. As an example, new innovative projects that provide longer term net gains in terms of cost and efficiency have been included, with resulting benefits incorporated into the Proposal. Further, economy of scale factors applied to output growth (refer Section 21.8) are representative of efficiency gains associated with customer, network and workforce growth.

It is also true that we cannot include all future costs in our forecasts. As with the current RCP, there will almost certainly be emerging environmental factors that will contribute to increasing costs for SA Power Networks in the next RCP, unknown at this time. A change to legislative requirements is one such example, potentially necessitating an increased compliance cost burden on SA Power Networks. Although we are aware that such future cost imposts are likely, we are not able to quantify these costs or their timing. Consequently, these emerging or 'uncontrollable costs' are unable to be identified in our Proposal.

Nor does the AER's 'uncertainty regime' allow recovery of any but the most significant of unforecast costs. The pass-through mechanism provides for the adjustment to allowances if a nominated future event materially impacts on SA Power Networks' costs. Together the cost impacts of future environmental factors could be material, however it is likely that individually, the majority would fall below the pass-through materiality threshold. Collectively however, the additional costs could lead to material increases in SA Power Networks' operating expenditure.

For the above reasons, SA Power Networks contends that it has developed its forecasts of operating expenditures in accordance with the operating expenditure objectives and criteria, and that there is an inadequate basis for estimating and applying a productivity adjustment in the rate of change formula.

21.11

Debt raising

Debt raising costs have been included as a component of the operating expenditure forecast, but not part of the base-step-trend approach. Debt raising costs are generally measured in basis points per annum (**bppa**). We have engaged Incenta Economic Consulting (**Incenta**) to provide an expert opinion on the total direct debt raising transaction costs that a benchmark efficient energy network service provider would be expected to incur in the course of the upcoming RCP. Incenta's report, provided in Section 4.2 of Attachment 21.2, considers the three sources of debt raising transaction costs being:

- costs of issuing debt for the assumed debt portfolio;
- costs to establish and maintain bank facilities required to meet Standard and Poor's liquidity requirements condition for maintaining an investment grade credit rating; and
- costs associated with the Standard and Poor's requirement, again as a condition of maintaining an investment grade credit rating, requiring us to refinance debt three months ahead of the refinancing date.

SA Power Networks understands that the approximate cost of these components is in the order of 21.3 bppa. This amount has been adopted in the forecast of operating expenditure. The final Incenta report, whilst attached to this Proposal, was not available at the time of writing. Each of the sub-components identified by Incenta are real costs that are incurred by us and other network service providers in the financing of operations and delivery of services. The total of the estimated debt raising costs for the 2015–20 RCP is $27.0 million, calculated using the Post Tax Revenue Model as shown in Table 21.16.

21.12

Contractual arrangements with external parties

We commercially contract out to numerous external parties to assist us in the delivery of SCS. This includes related party contracts with CHED Services, a party that shares ownership with SA Power Networks. The applicable contracts include:

- Contact Centre Agreement;
- FRC Shared Services Agreement; and
- FRC IT Support System Agreement.

The Contact Centre and FRC Shared Services Agreements have recently been negotiated and extended for the five year period, January 2014 to December 2018. As the contracts were not subject to a competitive tender process, we engaged KPMG to undertake a review of these contracts and benchmark the costs to ensure that the operating expenditure forecasts for the 2015–20 RCP are prudent and efficient. The KPMG report has been provided as Attachment 21.10, which demonstrates that the contracts include pricing and conditions that are consistent with commercial terms.

Table 21.16: Debt raising SCS 2015–20 (June 15, $ million)

June 2015 ($m)	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Debt raising	4.8	5.1	5.4	5.7	6.0	**27.0**

21.13

Alternative Control Services operating expenditure

Alternative Control Services (**ACS**) operating expenditure relates to metering services in respect of meters provided by SA Power Networks. Metering operating expenditure comprises the costs of maintaining, testing, and reading these meters, and the cost of managing the energy data they provide. (Network billing is a DNSP function and is therefore considered as part of SCS operating expenditure.)

SA Power Networks is required to comply with the requirements of the 'Responsible Person' role contained in the NER, and other technical and regulatory requirements. In addition to meeting these requirements, SA Power Networks' metering services aim is to ensure that relevant expenditure is prudent, efficient and focussed on ensuring that our metering equipment:

- is safe and accurate;
- supports our network pricing and tariff strategies;
- supports our network load management objectives and strategies; and
- is reasonably capable of efficiently supporting current and expected future relevant market and/or customer requirements.

Metering operating expenditure in the next RCP will be impacted by two key step changes:

- The AER's F&A for SA Power Networks reclassifies Type 5 metering services and energy data services as ACS, which have a material impact from 2015/16; and
- The metering-related impact of the introduction of capacity tariffs, which has a material impact from 2017/18.

21.13.1 Proposed operating expenditure

The total forecast operating expenditure of providing metering services for each year of the next RCP is shown in Table 21.17.

These forecasts are built up in our ACS pricing model and submission expenditure model, provided as Attachment 29.4 and Attachment 21.11 respectively.

The operating expenditure forecasting methodology for metering services uses a 'bottom-up' approach and includes determining forecast volumes of work and average unit costs for meter reading, meter maintenance and meter data services.

Volume forecasts are based on a combination of historical trend data and estimates on our future meter plans. Unit costs are based on historical costs with annual unit step increases in meter reading and meter data services costs occurring in 2017/18 reflecting the increased costs associated with moving from quarterly to monthly reads.

Our meter volume forecasting methodology is explained in detail in Attachment 29.3.

Meter reading

Meter reading refers to the scheduled reading of ACS meters, including the manual and remote collection of energy data from metering installations. Scheduled meter reading has been a component of ACS metering services since 2010.

As noted in Chapter 14, SA Power Networks proposes to transition all new customers and customers upgrading their supply arrangements to cost-reflective capacity tariffs from July 2017, consistent with AEMC proposed Rule change on distribution network pricing. As monthly meter reading is required to facilitate these tariffs, we are proposing to transition to monthly reading for all customers during 2017/18.[77]

Table 21.17: Forecast ACS metering services operating expenditure (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Meter reading	4.3	4.4	13.0	13.5	14.0	**49.2**
Maintenance	2.6	2.8	2.8	2.9	3.1	**14.2**
Energy data services	2.3	2.3	4.2	4.3	4.5	**17.6**
Corporate overhead	1.0	1.0	1.0	1.0	1.0	**5.1**
Total	**10.2**	**10.5**	**21.0**	**21.8**	**22.7**	**86.2**

77 The implementation of capacity tariffs also require meters that can measure maximum demand. This matter is discussed in Section 9 of Chapter 20.

SA Power Networks has considered an alternative approach, which is to transition customers to monthly reads progressively as they transition to capacity tariffs. Because customers transitioning to the new tariffs will be geographically dispersed, however, it would be inefficient to read meters for capacity tariff customers monthly and continue with quarterly reads for non-capacity tariff customers. Such a piecemeal approach would have significantly higher per-customer read costs and require more complex and costly scheduling of special reads.

As set out in Attachment 14.3 (Tariff and Metering Business Case) the proposed transition to monthly reading for all customers in 2017/18 is preferred because it enables significant economies of scale and provides the greatest advantages in terms of overall net cost, regulatory risk management, and administrative and scheduling efficiency.

Our proposed approach also has the advantage that it provides the benefit of monthly reading to all customers, not only those taking up the new tariffs. Significant beneficiaries are vulnerable customers, who are most susceptible to the bill shock that can be associated with quarterly billing.

The step change to meter reading costs resulting from the transition to monthly reading of all meters is approximately $8.5m per annum on average from 2017/18.

Meter maintenance
Meter maintenance activities include inspecting meters, investigating issues identified during inspections and by customers, scheduled sample testing, accuracy testing requested by customers, and undertaking routine and emergency meter repairs. SA Power Networks' Meter Asset Management Plan, provided as Attachment 21.24, sets out our strategy for the maintenance of metering and associated equipment.

The reclassification of Type 5 metering services as ACS primarily impacts meter maintenance costs. Nearly 90% of SA Power Networks' existing Type 5 meters are current transformer connected, and most of these will require their first five-year testing during the next RCP. The reclassification of existing Type 5 meters from Negotiated Distribution Services (**NDS**) to ACS drives a step change in meter maintenance of approximately $1.4m per annum on average.

Energy Data Services
Energy data services refers to the management of meter data after its collection. It involves the storage of energy data, the estimation, validation or substitution of energy data (as required and allowed); and the transmission of energy data to eligible market participants and the Australian Energy Market Operator (**AEMO**) for billing and market settlement purposes respectively.

SA Power Networks is an accredited 'Meter Data Provider' in respect of Types 5, 6 and 7 metering installations, but is not an accredited Meter Data Provider in respect of Types 1, 2, 3, and 4 metering installations. The remote reading and other energy data services for SA Power Networks' few Exceptional Type 1–4 meters is outsourced.

Energy data services are new to ACS for the next RCP. SA Power Networks has moved the costs of energy data services relevant to ACS from SCS costs. These are the costs relevant to the role of Meter Data Provider and not to that of DNSP. They include an allocation of personnel and service contract costs. The step change to ACS operating expenditure resulting from the reclassification of energy data services is approximately $2.25m per annum on average.

The eventual transition to monthly meter reading for all meters will drive a step increase in the cost of meter data management. We have estimated that the step change to energy data services costs will be approximately $1.9m per annum on average from 2017/18.[78]

Corporate overhead
Costs have been attributed and allocated to ACS metering services in accordance with the approved CAM.

78 The impact on billing costs has been dealt with in our SCS proposal.

22
Pass-Through Events

22

22.1

Rule requirements

NER clause 6.6.1 specifies 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.

SA Power Networks in accordance with clause 6.5.10(a) is permitted to include additional pass through events 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) (in the case of a distribution determination) or clause 6A.7.3(a1)(1) to (4) (in the case of a *transmission determination*);

(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 *Network Service Providers* is a nominated pass through event consideration.

SA Power Networks is not aware of any additional nominated pass through event considerations that the AER has notified Network Service Providers of under subclause (e) above.

22.2

Role of pass through events

The above structure works well for costs that are within the influence or control of the business. However, there are certain costs that are:

- beyond the control of the business: in other words it does not matter how well or how poorly the business manages its costs, the costs will be exogenously determined; or
- very difficult or impossible to estimate on a forward looking basis when setting the revenue or price cap.

Often the two will overlap. With respect to the former, as recognised by the AEMC in Final Determination[79] in response to Grid Australia's rule change request: *The Commission carefully considered submissions received from stakeholders in response to the consultation paper, and has responded to those submissions in this draft rule determination.*

With the exception of the capital expenditure re-opening provisions, the Commission considers that cost pass throughs should be the last option available to network businesses with respect to risk management. This is to protect the incentive mechanisms that operate under the building block approach to revenue determination, which help ensure that prices for consumers are no more than necessary to provide an appropriate level of service.

However, the Commission recognises that in order to provide network businesses with a reasonable opportunity to recover their efficient costs for providing direct control network services, network businesses should be able to recover the costs associated with events that are outside of their reasonable control.

In some cases insurance is an appropriate means of addressing the risk of these cost changes. In SA Power Networks' case the risks in relation to which insurance (via a policy or self insurance) is appropriate, and the events for which SA Power Networks has insurance or self-insures, are set out in Attachment 21.1.

Often, however, insurance coverage will be only partial, uneconomic to procure or in some cases, impossible to obtain at all.

On this basis, it will often be more efficient to 'pass through' these cost changes by permitting additional or requiring reduced, revenues or prices during the regulatory period.

Pass through events are in the long term interests of consumers of electricity when the events are not well suited to incentive regulation and it is a cheaper, or the only, way to manage the relevant risk. This was recognised by the AEMC Final pass through events rule determination[80] where it stated that:

79 AEMC Rule Determination titled "National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, dated 2 August 2012.

80 AEMC Rule Determination titled "National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, dated 2 August 2012, Section 2.5 titled "More preferable rule" pg 8.

'providing factors for consideration by the AER when approving nominated pass through events should help ensure that pass through events are only used in situations where commercial insurance and self-insurance are not available on a reasonable basis, or the NSP is unable to mitigate or avoid the event without creating unacceptable risks. This should protect the incentive regime under the NER and better promote the efficient investment in, and efficient operation and use of, network services for the long term interests of consumers of electricity with respect to price;'

Having said that, the AER is of course not required to approve a cost pass through just because a particular nominated event has occurred. First an application would have to be made to the AER demonstrating that the particular event has occurred and that it has materially increased (or decreased) the costs of providing direct control services, and the AER would then have to determine under NER 6.6.1(d)(2) that an amount should be passed through to customers. The inclusion of a pass through event therefore does not remove regulatory oversight.

In addition, pursuant to clause 6.6.1(j) of the Rules, the distribution business must take measures to reduce the magnitude of the pass through amount:

'In making a determination [relating to a pass through amount] … the AER must take into account:
…
3) in the case of a positive change event, the efficiency of the provider's decisions and actions in relation to the risk of the positive change event, including whether the provider has failed to take any action that could reasonably be taken to reduce the magnitude of the eligible pass through amount … and whether the provider has taken or omitted to take any action where such action or omission has increased the magnitude of the amount in respect of that positive change event.'

On that basis, in relation to each nominated pass through event, SA Power Networks will retain its incentive to operate efficiently and mitigate its increased costs.

For the reasons discussed above, it is not likely to promote efficient investment in electricity services, nor is it in the long term interests of consumers of electricity, for distribution businesses to bear remote risks, which may never eventuate, and are outside of their control.

22.3

Proposed additional pass through events

SA Power Networks has identified six potential additional pass through events which may occur in the next RCP.

22.3.1
Kangaroo Island cable failure event

SA Power Networks proposes a pass through event for a 'Kangaroo Island cable failure event'. The proposed definition of a Kangaroo Island cable failure event is:

"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."

During normal operation, customers on Kangaroo Island are supplied with electricity through a single 33kV submarine cable in Backstairs Passage connecting to the mainland electricity network. Stand-by diesel generation at Kingscote occasionally operates, on a temporary basis, to maintain customer supply when there is an unplanned loss of supply or when network maintenance is undertaken.
In the event of the 33kV submarine cable failing, SA Power Networks would be required to operate the standby generators on a 24 hour–7 days a week basis to meet customer electricity supply requirements.

Failure of the undersea cable would be difficult and could be impractical to repair due to its depth. The replacement/repair requires a specialised ship, which could take several months to arrive and commence operations. It is expected that the time to replace or repair the cable is six to 12 months and the estimated cost of running the Kingscote Generators is about $2.5 million per month.

It would be inappropriate for this cost to be included in our five yearly funding, but the cost should be passed through to customers if the event occurs, as a failure is beyond SA Power Networks' control.

SA Power Networks has experienced one Kangaroo Island cable fault in the past. Fortunately the cable failed in the land section and was able to be repaired within a relatively short period of time. Consequently, the costs of the repair and maintaining electricity supply to the Island were not material (ie they did not exceed one percent of annual revenue).

In further support of this pass through event, SA Power Networks notes that:

- a Kangaroo Island cable failure event is not already covered by any of the categories of prescribed pass through events set out in NER 6.6.1(a1)(1) to (4);
- the nature or type of event can be clearly identified;
- as a prudent service provider, SA Power Networks cannot reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event prior to the event occurring. In addition, we note that the AER will, as part of its determination of the amount of the pass through, consider the efficiency of SA Power Networks' decisions and actions to mitigate the cost of the event (see NER 6.6.1(j)(3)); and

- SA Power Networks is unable to obtain appropriate insurances that are commercially viable, for this type of event.

22.3.2
Natural disaster event

SA Power Networks proposes a pass through event for a 'Natural disaster event'. The proposed definition of a Natural disaster event is:

"Any major fire, storm, flood, earthquake, or other natural disaster 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."

In support of this pass through event, SA Power Networks notes that:

- a natural disaster event is not already covered by any of the categories of prescribed pass through events set out in NER 6.6.1(a1)(1) to (4);
- the nature or type of event can be clearly identified;
- it is difficult for SA Power Networks to mitigate the nature or cost of the event, prior to the event occurring. In addition, we note that the AER will as part of its determination of the amount of the pass through the AER musty consider the efficiency of SA Power Networks' decisions and actions to mitigate the cost of the event (see NER Rule 6.6.1(j)(3));
- SA Power Networks is unable to obtain appropriate insurances that are commercially viable, for this type of event;
- a natural disaster event is not foreseeable, has a low probability but a high consequence or magnitude; and
- a natural disaster event is beyond the control of SA Power Networks.

We note that a similar pass through event was approved by the AER in its Final Determination for the Victorian Distributors in 2010 and Aurora Energy in 2012.

SA Power Networks has included major storms in the natural disaster definition above as SA Power Networks is required to make long duration GSL payments on Major Event Days, unlike other distributors. The requirements to make long duration GSL payments on Major Event Days can significantly increase the cost of an extreme storm (eg a one in ten year storm).

22.3.3
Liability above insurance cap event

SA Power Networks proposes a pass through event for a 'Liability above insurance cap event'. The proposed definition of the Liability above insurance cap event is:

- *A Liability above insurance cap event occurs if:*
  - *SA Power Networks makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy,*
  - *SA Power Networks incurs costs beyond the relevant policy limit, and*
  - *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:*
  - *the relevant policy limit is the greater of:*
  - *SA Power Networks' actual policy limit at the time of the event that gives, or would have given rise to a claim, and*
  - *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.*
  - *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 a Liability above insurance cap event cost pass through application under rule 6.6.1(j), the AER will have regard to:*
  - *the insurance premium Proposal submitted by SA Power Networks in its regulatory Proposal;*
  - *the forecast operating expenditure allowance approved in the AER's final decision; and*
  - *the reasons for that decision.*

In support of this pass through event, SA Power Networks notes that:

- a liability above insurance cap pass through event is not already covered by any of the categories of prescribed pass through events set out in NER 6.6.1(a1)(1) to (4);
- a liability above insurance cap pass through event is not foreseeable;
- a liability above insurance cap pass through event has a low probability but a high consequence or magnitude; and
- a liability above insurance cap pass through event is beyond the control of SA Power Networks.

We note that a similar pass through event was approved by the AER in its Final Determination for the Victorian Distributors in 2010, Aurora Energy in 2012, and SP Ausnet (Transmission) in 2014.

22.3.4
Insurer credit risk event

SA Power Networks proposes a pass through event for an 'insurer credit risk event'. This event would be triggered where SA Power Networks' insurer becomes insolvent, and SA Power Networks is subject to higher or lower premiums than those allowed in the Distribution Determination or a higher or lower claims limit or deductible than those allowed under its insurance policy with that insurer.

The proposed definition of the Insurer credit risk event is:

The insolvency of a nominated insurer of SA Power Networks, as a result of which SA Power Networks:

(i) incurs materially higher or lower costs for insurance premiums than those allowed for in the Distribution Determination; or

(ii) in respect of a claim for a risk that would have been insured by SA Power Networks' insurers, is subject to a materially higher or lower claims limit or a materially higher or lower deductible than would have applied under that policy.

In support of this pass through event, SA Power Networks notes that:

- an insurer credit risk pass through event is not already covered by any of the categories of prescribed pass through events set out in NER 6.6.1(a1)(1) to (4);
- an insurer credit risk pass through event is not foreseeable;
- an insurer credit risk pass through event has a low probability but a high consequence or magnitude; and
- an insurer credit risk pass through event is beyond the control of SA Power Networks.

SA Power Networks submits that the occurrence of increased insurance premiums (or deductibles) from external insurers (where the original insurer becomes insolvent) is beyond the control of SA Power Networks (subject to any choice that SA Power Networks has with regard to insurance companies), and that the costs associated with higher insurance premiums are also beyond the control of SA Power Networks (as they cannot be mitigated).

We note that a similar pass through event was approved by the AER in its Final Determination for the Victorian Distributors in 2010 and Aurora Energy in 2012.

22.3.5 Native title event

SA Power Networks proposes a pass through event for a 'native title event'. The proposed definition of a native title event' is:

"An event whereby, as the result of a native title claim, SA Power Networks incurs material costs constituting:

- *any compensation or damages payable by SA Power Networks, for example as a result of a registered Indigenous Land Use Agreement (**ILUA**), a consent determination or a decision of a Court; and/or*
- *legal fees and disbursements associated with negotiation and litigation in relation to native title claims."*

SA Power Networks is currently involved in 10 native title matters. SA Power Networks' current intention is to resolve these claims by ILUAs or consent determination, on the basis of timetables set by the Federal Court.

In support of this pass through event, SA Power Networks notes that:

- a native title event is not already covered by any of the categories of prescribed pass through events set out in NER 6.6.1(a1)(1) to (4);
- the nature or type of event can be clearly identified;
- as a prudent service provider, SA Power Networks cannot reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event prior to the event occurring. In addition, we note that the AER will, as part of its determination of the amount of the pass through, consider the efficiency of SA Power Networks' decisions and actions to mitigate the cost of the event (see NER 6.6.1(j)(3)); and
- SA Power Networks is unable to obtain appropriate insurances that are commercially viable, for this type of event.

In addition it is appropriate that compensation and substantial legal fees and disbursements associated with native title claims be able to be passed through to consumers for the following reasons:

- native title matters are uncontrollable, in that SA Power Networks through its actions could not have avoided the claims;
- native title matters differ from other, commercially focussed legal matters and litigation. SA Power Networks notes the AER's draft decision not to permit as pass through events for its draft NSW Distribution Determinations for 2009/10 to 2013/14, events related to court decisions generally, including for the reason that incidents that occurred in the past should not be passed on to current or future users. However, SA Power Networks notes the following factors that distinguish native title actions from other types of litigation:
  - the claims do not arise as a result of commercial decisions made by the distribution business; and
  - the claims could not have been avoided through putting in place different business practices in the past; and
  - failure to nominate native title events as pass through events will adversely impact current or future users, because SA Power Networks has not made provision for native title compensation in its Proposal.

22.3.6 General nominated pass through event

SA Power Networks proposes as a nominated pass through event a 'general nominated pass through event'. The proposed definition of a 'general nominated pass through event', as replicated from the current determination for our 2010–15 RCP is:

A general nominated pass through event occurs in the following circumstances:

1. *An uncontrollable and unexpected event occurs during the next regulatory control period, the effect of which could not have been prevented or mitigated by prudent operation risk management.*
2. *The change in costs of providing distribution services as a result of the event is material.*
3. *The event does not fall into any of the following definitions:*
   a 'regulatory change event' in the NER (read as if paragraph (a) of the definition was not part of the definition)
   a 'service standard event';
   a 'tax change event';
   a 'retailer insolvency event'; and
   any other event specified in a distribution determination as a pass through event for the determination.

SA Power Networks understands that it must employ prudent operational risk management to mitigate the costs of such an event, if it was to occur.

A general nominated pass through event was included in SA Power Networks' (then ETSA Utilities) previous regulatory determination. In 2013, the general nominated cost pass through event category was utilised to recover the material increase in vegetation management costs associated with the cessation of the millennium drought, after the significant increase in vegetation growth rates. Due to the prescriptive regulatory regime in South Australia the only practical response whilst still complying with our regulatory obligations was to increase the frequency of vegetation clearance, materially increasing the cost of providing direct control services.

In the absence of a general nominated pass through event being available, if a similar event was to occur during the next RCP, we would be prevented from recovering the additional costs of complying with our obligations. NEL Section 7A includes the following principle amongst others, which is particularly relevant to the treatment of such a pass though event:

(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in —
- *(a) providing direct control network services; and*
- *(b) complying with a regulatory obligation or requirement or making a regulatory payment.*

In the case of the 2013 pass through event, if a general nominated pass through event had not been available, it could have potentially undermined our ability to provide direct control services or threatened our ability to maintain an acceptable risk profile.

In support of this general nominated pass through event, SA Power Networks notes that:
- a general nominated pass through event is not already covered by any of the categories of prescribed pass through events set out in NER 6.6.1(a1)(1) to (4);
- we consider that the nature of this type of event can be clearly identified even if the event can not be clearly identified;
- a general nominated pass through event is not foreseeable (eg as was the case in the breaking of the millennium drought);
- a general nominated pass through event has a low probability but a high consequence or magnitude; and
- a general nominated pass through event is beyond the control of SA Power Networks.

22.4

Retailer insolvency event

A retailer insolvency event was introduced with no materiality threshold for the failure of a retailer. However, due to amendments to the NER the current definition of a positive change event applies a one percent materiality requirement.The current definition of a positive change event in the NER V64 Chapter 10 states:

Positive change event
- *for a Distribution Network Service Provider, a pass through event which entails the Distribution Network Service Provider incurring materially higher costs in providing direct control services than it would have incurred but for that event, but does not include a contingent project or an associated trigger event; and*
- *for a Transmission Network Service Provider, a pass through event which entails the Transmission Network Service Provider incurring materially higher costs in providing prescribed transmission services than it would have incurred but for that event, but does not include a contingent project or an associated trigger event.*

This definition by default imposes a 1% materiality threshold on a retailer insolvency event, which is clearly against the intentions of the NECF implementation. This is reinforced by the "The Making of the National Electricity (National Energy Retail Law) Amendment Rule 2012" signed by The SA Energy Minister on 27 June 2012, which states for a positive change event:

Positive change event
- *(a) for a Transmission Network Service Provider, a pass through event that materially increases the costs of providing prescribed transmission services, but does not include a contingent project or an associated trigger event.*
- *(b) for a Distribution Network Service Provider, a pass through event that materially increases the costs of providing direct control services.*
- *(c) for a Distribution Network Service Provider, a pass through event that is a retailer insolvency event that increases the costs of providing direct control services.*

This definition made by the SA Minister carved out a retailer insolvency event from any materiality test. This definition was never incorporated into a published version of the NER. This omission needs to be corrected and we ask the AER to note that SA Power Networks will be raising the matter with the AEMC.

23
Incentive schemes

23

23.1

Capital Expenditure Sharing Scheme (CESS)

This section sets out SA Power Networks' Proposal in relation to the application of the Capital Expenditure Sharing Scheme (**CESS**).

23.1.1
Rule requirements

From 1 July 2015, the AER will apply an ex-ante CESS to provide financial rewards for distributors whose capex becomes more efficient and financial penalties for those that become less efficient.

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 capital expenditure incentive objective[81]; and
- consider the CESS principles[82], interaction of the CESS with incentive schemes, capital expenditure objectives, and where relevant the operating expenditure objectives[83], as they apply to the particular DNSP, and the circumstances of the DNSP[84].

The AER will also introduce ex-post measures to ensure that only efficient capital expenditure enters the 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 2020–25 regulatory determination process.

23.1.2
CESS

The overarching objective of the CESS is to provide NSPs with an incentive to undertake efficient capex during a RCP. It achieves this by rewarding NSPs that outperform their capex allowance and penalising NSPs that spend more than their capex allowance. The CESS also provides a mechanism to share efficiency gains and losses between NSPs and network users.[85]

In its Framework and Approach paper, the AER has expressed its position to apply the CESS, as set out in its Capital Expenditure Incentive Guideline, to SA Power Networks in the next RCP.[86]

The CESS will work as follows at the end of the 2015–20 RCP:

- cumulative underspend or overspend of capex allowances will be calculated for the 2015–20 RCP in net present value terms;
- capex allowances for the 2015–20 RCP will be adjusted for allowed pass throughs, reopening of capex or contingent projects during the 2015–20 RCP;
- a sharing ratio of 30 per cent will be applied to the cumulative underspend or overspend to calculate the DNSP's share of the underspend or overspend; and
- forecast depreciation will be applied to roll-forward the RAB from 1 July 2015 to 30 June 2020.

SA Power Networks supports the introduction of the CESS in the 2015–20 RCP. In tandem with the EBSS, the CESS provides appropriate and balanced incentives for efficient expenditure.

23.1.3
Ex-post measures for efficient capital expenditure

The AER may exclude capex from the RAB under an ex-post review:

- when a DNSP has overspent, the amount of capex above the allowance that does not reasonably reflect the capital expenditure criteria can be excluded from the RAB;
- where there is an inflated related party margin, the inflated portion of the margin can be excluded from the RAB; and
- where a change to a DNSP's capitalisation policy has led to opex being capitalised, the capitalised opex can be excluded from the RAB.

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.

However, under clause 11.60.5 of the NER, the AER can only exclude from the RAB capex incurred in regulatory years following the publication of the Capital Expenditure Incentive Guideline in November 2013. These transitional arrangements will apply for SA Power Networks' distribution determination for the 2020–25 RCP, whereby the assessment will be for the regulatory years 2014/15 (being the first regulatory year after the publication of the Capital Expenditure Incentive Guideline) to 2017/18 (being the third regulatory year of the 2015–20 RCP) inclusive.

SA Power Networks advocates that full and transparent consultation be undertaken at all stages of any ex-post review.

81 NER, clause 6.5.8A(e)
82 NER, clause 6.5.8A(c)
83 NER, clause 6.5.8A(d)
84 NER, clause 6.5.8A(e)
85 AER, Capital Expenditure Incentive Guideline, November 2013, page 7
86 AER, Final framework and approach for SA Power Networks, April 2014, p65

23.2

Efficiency Benefit Sharing Scheme (EBSS)

23.2.1
Summary of Proposal

This section sets out SA Power Networks' Proposal in relation to the application of the efficiency benefit sharing scheme (**EBSS**). It deals with two separate aspects of SA Power Networks' Proposal:

- the calculation of the EBSS carryover amounts from the current RCP, which are used in the calculation of SA Power Networks annual revenue requirement for the next RCP; and
- the way in which the EBSS is to be applied in the next RCP.

23.2.2
Summary of EBSS in the 2010–15 RCP

SA Power Networks has calculated carryover amounts from the current RCP, in accordance with the EBSS which applied during that period (as set out in the 2010 Determination) and the relevant requirements of the Rules.

Proposed carryover amounts from the current RCP are set out in Table 23.1 below. Further detail on calculation of these amounts is set out in Section 23.2.5 below.

Table 23.1: 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 these proposed carryover amounts is based on its actual operating expenditure for the current RCP, adjusted only for:

- costs associated with approved pass through events during that period;
- 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.

Each of these adjustments is described below.

The benchmark operating expenditure allowance used to calculate carryover amounts is as set out in the AER's May 2010 distribution determination for ETSA Utilities, adjusted only to remove the allowance that was made for feed-in tariff payments in each of the regulatory years 2011/12 to 2014/15 and the component of the benchmark allowance attributable to MED-related GSL costs.

This benchmark allowance accounts for the deferred carryover from the 2005–10 RCP.

23.2.3
Application of the EBSS in the 2015–20 RCP

SA Power Networks supports continued application of the EBSS in the 2015–20 RCP. SA Power Networks also generally supports the AER's proposed approach to application of this scheme for the next RCP, as set out in the November 2013 EBSS Guideline, and the Framework and Approach Paper, subject to the retention of specific exclusions and adjustments, discussed further in Section 23.2.6.

SA Power Networks proposes to retain the same excluded cost categories that applied in the current RCP, for the purposes of applying the EBSS in the next RCP. Additionally, SA Power Networks proposes to exclude MED-related duration GSL payments from the operation of the EBSS in the next period. The reasons for each of the proposed exclusions are discussed in Section 23.2.6 below.

23.2.4
Rule requirements

The Rules set out two relevant requirements in relation to the EBSS:

- the building blocks used to calculate the annual revenue requirement for each regulatory year of the next RCP (to be specified in the building block determination) must include (among other things) any revenue increments or decrements for the relevant regulatory year arising from the application of any EBSS;[87] and
- the building block determination must also specify how any applicable EBSS is to apply to the DNSP in the next RCP.[88]

The EBSS which applies to SA Power Networks in the current RCP (and which gives rise to revenue increments and decrements for the next RCP) is the EBSS specified in the 2010 Determination.[89] This determination refers to the EBSS as set out in the AER's earlier Framework and Approach Paper for ETSA Utilities (November 2008)[90], which in turn refers to the distribution EBSS established by the AER in June 2008.[91]

The 2010 Determination also 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 ESCoSA scheme.

The EBSS to apply in the next RCP must be developed and implemented in accordance with clause 6.5.8 of the Rules. Under clause 6.5.8(c), the AER must have regard to the following matters in developing and implementing an EBSS for the next RCP:[92]

- 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; and

87 NER, clause 6.4.3(a)(5).
88 NER, clause 6.3.2(a)(3).
89 AER, ETSA Utilities distribution determination 2010–11 to 2014–15, 4 May 2010.
90 AER, Framework and approach paper: ETSA Utilities 2010–15, November 2008.
91 AER, Electricity distribution network service providers: Efficiency benefit sharing scheme, June 2008.
92 NER, clause 6.5.8(c).

- the need to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure; and
- the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses; and
- any incentives that DNSPs may have to capitalise expenditure; and
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

In its Framework and Approach Paper, the AER proposes to apply its new EBSS (published in November 2013) to SA Power Networks for the 2015–20 RCP. The AER says that its distribution determination for SA Power Networks will specify how this EBSS will be applied in the 2015–20 RCP.

23.2.5
Carryover amounts from the 2010–15 RCP

The increments and decrements (carryover amounts) to be included in the revenue building blocks for the next RCP are those arising from the application of the EBSS in the current RCP.

As noted above, the EBSS which applies to SA Power Networks is the EBSS specified in the 2010 Determination. This determination specified that:[93]

In accordance with clause 6.12.1(9) of the NER, the EBSS to apply to ETSA Utilities is as set out in the AER's Final decision, Framework and approach paper, ETSA Utilities 2010–15, published in November 2008.

The fourth paragraph in clause 2.3.2 of the applicable EBSS provides, in part that 'the AER will permit a DNSP to propose a range of additional cost categories for exclusion from the operation of the EBSS' and that 'a DNSP must propose cost categories for exclusion from the EBSS in their regulatory proposal prior to the commencement of the regulatory control period during which the EBSS will be applied'.

In our proposal for the current regulatory control period, we did propose a range of exclusions including 'expenditure that meets all the necessary requirements for an approved pass through event other than satisfying the materiality threshold'. Although that category was not accepted by the AER, the AER did, in accordance with the sixth paragraph of clause 2.3.2 of the EBSS, approve for exclusion a category of 'other specific uncontrollable costs incurred and reported by (SA Power Networks) during the next regulatory control period (ie the 2010–15 RCP), which the AER considers should be excluded after assessment against the relevant principles expressed in clause 6.6.1(j) of the NER and the EBSS'.

In its 2010 Determination, the AER specified that[94]:
The following opex cost categories will be excluded from the operation of the EBSS for the next *regulatory control period*:

- *debt raising costs;*
- *insurance and self insurance costs;*
- *superannuation costs for defined benefits and retirement schemes;*
- *the demand management innovation allowance; and*
- *other specific uncontrollable costs incurred and reported by ETSA Utilities during the next RCP, which the AER considers should be excluded after assessment against the relevant principles expressed in clause 6.6.1(j) of the NER and EBSS.*

These excluded costs will be recognised in addition to the adjustments and exclusions set out in Section 2.3.2 of the EBSS, which include non–network alternatives and recognised cost pass throughs events. Any negative opex carryover accrued under the current RCP Efficiency Carryover Mechanism can be deferred to offset any positive carryover accrued in the next RCP, provided the negative carryover is accrued in an approved uncontrollable opex category under the EBSS.

Set out below is SA Power Networks' calculation of proposed carryover amounts to be included in the revenue building blocks for the forthcoming RCP, based on application of this EBSS.

Actual operating expenditure for the 2010–15 RCP
SA Power Networks' total operating expenditure associated with standard control services in the first four years of the 2010–15 regulatory control period is set out in Table 23.2 below.[95]

Table 23.2: SA Power Networks operating and maintenance expenditure — standard control services ($ million, nominal)

	2010/11	2011/12	2012/13	2013/14
Total operating expenditure — standard control services	208.1	206.7	225.4	236.8

Adjustments to actual operating expenditure
In establishing the EBSS to apply in the 2010–15 RCP, the AER identified certain categories of operating expenditure which would be excluded from the operation of the scheme. The excluded cost categories include those set out in Section 2.3.2 of the EBSS which applied at that time, and certain additional cost categories set out in the 2010 Determination (referred to above).[96]

93 AER, ETSA Utilities distribution determination 2010–11 to 2014–15, 4 May 2010, p 3.

94 AER, ETSA Utilities distribution determination 2010–11 to 2014–15, 4 May 2010, p 3

95 Actual operating expenditure for 2014/15 is not yet available. As discussed below, under the AER's EBSS actual operating expenditure for the final year of the regulatory control period is estimated based on the forecast for that year, and efficiency gains/losses in the forecast base year.

96 AER, *Final decision: South Australia distribution determination 2010–11 to 2014–15*, May 2010, pp 207–208.

Adjustments for capitalisation policy changes and demand growth

There have been no changes to capitalisation policies during the current RCP, therefore no associated EBSS adjustment is required. No demand growth adjustment mechanism applies to SA Power Networks in the current RCP.

Adjustments for costs associated with pass through events

The EBSS which applied at the time of the AER's 2010 distribution determination for ETSA Utilities stated that approved increases or decreases in actual operating expenditure associated with recognised pass through events would be excluded from the actual and forecast expenditure amounts used to calculate carryover gains or losses under the EBSS.[97]

SA Power Networks has incurred additional costs associated with an approved pass through event (vegetation clearing) during the 2010–15 RCP. This pass through event and associated pass through amounts was approved by the AER in July 2013.[98]

The approved increases in expenditure associated with this pass through event for the first four years of the RCP are set out in Table 23.3 below.

Table 23.3: Approved pass through amounts ($ million, nominal)

	2010/11	2011/12	2012/13	2013/14
Vegetation management pass through amounts	-	-	14.9	11.4

Adjustments for cost categories identified in the 2010 Determination

In the 2010 Determination, the AER stated that the following specific cost categories would be excluded from the operation of the EBSS for the 2010–15 RCP:[99]

- debt raising costs;
- insurance and self-insurance costs;
- superannuation costs for defined benefits and retirement schemes;
- non-network alternatives; and
- the demand management innovation allowance (**DMIA**).

Table 23.4 below sets out SA Power Networks' expenditure in the first four years of the 2010–15 RCP in each of these specific excluded cost categories.

Table 23.4: Expenditure in excluded cost categories identified by the AER ($ million, nominal)

	2010/11	2011/12	2012/13	2013/14
Debt raising costs	2.2	2.4	2.4	1.9
Insurance	2.4	2.7	3.3	2.9
Self-insurance	0.4	0.9	1.2	5.0
Superannuation costs for defined benefits and retirement schemes	6.3	5.2	4.6	3.2
DMIA	0.0	0.0	0.0	1.4
Non-network alternatives	0.0	0.0	0.0	0.3
Total	**11.4**	**11.2**	**11.5**	**14.8**

Adjustments for other specific uncontrollable costs

As noted above, in the 2010 Determination the AER stated that it would also exclude other specific uncontrollable costs incurred and reported by SA Power Networks during the 2010–15 RCP from the operation of the EBSS for that period.

The AER's decision to exclude uncontrollable costs from the EBSS reflected recognition that businesses should not receive benefits or penalties through the EBSS for variances in operating expenditure in cost categories over which they have no control. The AER has noted that this approach is consistent with clause 6.5.8(c) of the NER, which requires the EBSS to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure.[100] Excluding uncontrollable cost categories from the operation of the EBSS is consistent with this requirement because there can be no incentive for businesses to reduce operating expenditure in cost categories over which they have no control.

The 2010 Determination stated that it would assess any proposal for exclusion of other uncontrollable cost categories against the relevant principles expressed in clause 6.6.1(j) of the NER and in the EBSS. The principles set out in clause 6.6.1(j) are the principles that apply to the AER's assessment of a pass through application, and include:

- the increase in costs that has occurred in connection with the event;[101]
- the need to ensure that only the actual or likely increment in costs is recovered, to the extent that such increment is solely as a consequence of the event;[102] and
- the efficiency of the DNSP's decisions and actions in relation to the risk of the event, including whether the DNSP has failed to take any action that could reasonably be taken to reduce the magnitude of the costs associated with the event.[103]

97 AER, *Electricity distribution network service providers: Efficiency benefit sharing scheme*, June 2008, p 7.
98 AER, *Final Decision: SA Power Networks cost pass through application for vegetation management costs arising from an unexpected increase in vegetation growth rates*, July 2013.
99 AER, *Final decision: South Australia distribution determination 2010–11 to 2014–15*, May 2010, pp 207–208.
100 AER, *Draft decision: South Australia distribution determination 2010–11 to 2014–15, November 2009*, p 373.
101 NER, clause 6.6.1(j)(2).
102 NER, clause 6.6.1(j)(5).
103 NER, clause 6.6.1(j)(3).

SA Power Networks has incurred uncontrollable costs in two other categories (in addition to those listed above) during the 2010–15 regulatory control period:

- uncontrollable GSL payments associated with extreme weather events; and
- regulatory compliance costs associated with new reporting requirements.

Each of these items is discussed below.

Uncontrollable GSL payments associated with extreme weather events

SA Power Networks is obliged to pay a customer a long duration (**LD**) GSL payment where there is a failure of the distribution system that results in a LD interruption to a customer. The duration of the LD interruption and the associated payment is specified in Table 23.5 below.[104]

Table 23.5: LD GSL amounts payable by SA Power Networks

Duration of interruption	GSL payment
>12 & ≤ 15 hours	$90
>15 & ≤ 18 hours	$140
>18 & ≤ 24 hours	$185
> 24 hours	$370

SA Power Networks is in a unique position in relation to its obligation to make LD GSL payments. Unlike other DNSPs, SA Power Networks may be required to make LD GSL payments in connection with uncontrollable extreme weather events which cause a failure of the distribution system. This is because, unlike the AER STPIS, the ESCoSA GSL scheme does not exclude liability for these payments on extreme weather event days. This means that where uncontrollable extreme weather events occur, SA Power Networks is required to make GSL payments to customers for any associated LD network interruptions.

Under the AER STPIS, a DNSP is not required to make GSL payments when the thresholds are exceeded as a result of an event where daily USAIDI for the DNSP's distribution network exceeds the relevant MED boundary.[105] This has the effect of excluding liability for GSL payments on MEDs, for DNSPs subject to the AER's GSL scheme, as set out in the STPIS.

However SA Power Networks is subject to obligations under the ESCoSA GSL scheme, and is not subject to the AER's GSL scheme, as set out in the STPIS.[106] SA Power Networks liability for GSL payments arises under the South Australian Electricity Distribution Code.

Under the Electricity Distribution Code, there is no exclusion of liability for GSL payments on extreme weather event days. The only exclusions that apply under this scheme are for: interruptions caused by transmission and generation failures; interruptions caused by disconnection required in an emergency situation (eg bushfire); interruptions caused by single customer faults caused by that customer; interruptions of duration less than 1 minute; and planned interruptions.[107]

It would therefore be appropriate and consistent with the requirements of the Rules for GSL payments associated with extreme weather events to be excluded from the operation of the EBSS. In particular, excluding this uncontrollable cost item is consistent with the requirement to provide SA Power Networks with a continuous incentive to reduce operating expenditure, because there can be no incentive for SA Power Networks to reduce operating expenditure in a cost category over which it has no control.

SA Power Networks has broken down its GSL payments for the 2010–15 RCP into 'controllable' and 'uncontrollable' payments, so as to ensure that only the increment in costs that is consequential on uncontrollable events is excluded from the operation of the EBSS (consistent with clause 6.6.1(j)(5) of the NER). For this purpose, uncontrollable GSL payments are defined as those made in connection with 'major event days', while controllable GSL payments are all remaining GSL payments, not made in connection with 'major event days'. As discussed below, 'major event days' for this purpose are as defined in the AER's STPIS. Thus, 'uncontrollable' GSL payments are limited to those GSL payments which SA Power Networks would not be required to make, if it were subject to the AER's GSL scheme, as set out in the STPIS.

Major Event Day — Categorisation

South Australia experiences about 35 Bureau of Meteorology (**BoM**) reported significant weather events (SWE) annually, with on average about one in seven of those events resulting in a MED. SA Power Networks refers to those coincident BoM SWE and MEDs as a Major Severe Weather Event (**MSWE**).

MEDs are defined in the AER STPIS as any day where the daily USAIDI[108] exceeds a pre-determined threshold value (T_{MED}). T_{MED} is calculated from the previous five consecutive years' daily USAIDI data, using the 2.5 Beta statistical method. On average there are about six MEDs annually. On average there was one MED annually that did not coincide with a BoM SWE during the 2005–10 RCP, compared with zero during the 2010–15 period (ie all MEDs coincided with a BoM SWE).

USAIDI provides a reasonable measure of the severity of MEDs. Over the eight regulatory years since 1 July 2005 the MED USAIDI value has varied from 4.6 to 62.3[109] minutes. In general as the MED's daily USAIDI increases the number of LD GSL payments also increases.

104 Electricity Distribution Code (SA), EDC/10, February 2013, clause 1.1.4.4.
105 AER, Electricity distribution network service providers: Service target performance incentive scheme, November 2009, clause 6.4(b).
106 AER, Electricity distribution network service providers: Service target performance incentive scheme, November 2009, clause 6.1(a).
107 Electricity Distribution Code (SA), EDC/10, February 2013, clause 1.1.4.4. The same set of exclusions also appeared in earlier versions of the Code.
108 Any interruption's USAIDI contribution is accrued to the day that the interruption commenced.
109 62.3 minutes represents more than 1/3rd of the average annual USAIDI target (equivalent). SA Power Networks is not subject to an overall USAIDI target.

However, in some cases a similar value of USAIDI for two MEDs can result in significantly different numbers and cost of LD GSL payments.

This can result from one MSWE only affecting a particular location and the other affecting a greater number of locations. This difference in the area affected results in the more localised MSWE leading to greater LD GSL payments.

SA Power Networks has categorised its MSWEs (ie coincident BoM SWE and MED) based on the MSWEs USAIDI when reporting to ESCoSA, as set out in Table 23.6 below. This categorisation allows for analysis of MSWEs with similar values of USAIDI and customer outcomes. However, as highlighted above some MSWEs will be atypical despite being in the same category.

Table 23.6: SA Power Networks categorisation of MSWEs[110]

MED category	USAIDI range (mins)	Duration GSLs ($m)
Category 1 (**Cat1**)	T_{MED} < daily USAIDI ≤ 9	$0.1–$0.2
Category 2 (**Cat2**)	9 < daily USAIDI ≤ 23	$0.2–$1.1
Category 3 (**Cat3**)	23 < daily USAIDI ≤ 46	$0.4–$2.1
Category 4 (**Cat4**)	daily USAIDI > 46	> $3.0

Amount of LD GSL payments on MEDs
The vast majority of SA Power Networks GSL payments result from LD supply interruptions, and the majority of the costs of LD GSL payments result from interruptions which commence on MSWEs. LD GSL payments associated with MSWEs represented about 54% and 86% of the total LD payments during the 2005–10 and 2010–15 periods respectively.

There has been a significant increase in the number and the cost of LD GSL Payments associated with MSWE MEDs in the 2010–15 RCP. These increases have been the result of the emergence of Cat3 and Cat4 events, and the increase in the number of Cat2 events. The average annual number of Cat2, 3 and 4 MEDs associated with MSWEs has increased from 0.4 in the 2005–10 period to 3.0 in the 2010–15 period.

The majority of the MSWE Cat2, Cat3 and Cat4 MEDs during 2010–15 have resulted in extensive damage to distribution system infrastructure. The damage results from large trees and tree limbs falling onto power lines. The damage has required the replacement of poles, cross arms, and conductors to enable the restoration of supply to customers. This extensive rebuilding of power lines to enable the restoration of customers' supply resulted in considerable delays in restoring power and significantly increased the costs and number of LD GSL payments. These delays can in some cases be accentuated by legal restrictions on SA Power Networks' ability to restore supply — for example, SA Power Networks is not permitted under legislation to remove trees or clear trees away from power lines to prevent trees or tree limbs falling onto power lines, during MSWEs.

Table 23.7 below sets out the number of MSWE Cat1, 2, 3 and 4 MEDs, and the number and cost[111] of LD GSL payments associated with these MEDs between 2005/06 and 2013/14. This shows a significant increase in LD GSL payments over the past four years, associated with the emergence of Cat3 and Cat 4 MSWEs, and the increase in the number of Cat2 MSWEs.

Table 23.7: MSWE MEDs and GSL payments, 2005–14

	Number of MEDs				GSL Duration Payments	
Regulatory Year	Cat1	Cat2	Cat3	Cat4	No.	$
2005/06*	6	0	-	-	8,780	1,564,400
2006/07*	5	0	-	-	1,996	315,040
2007/08	1	0	-	-	28	2,960
2008/09	2	1	-	-	4,055	422,320
2009/10	2	1	-	-	2,476	298,880
2010/11	4	0	5	-	34,918	6,065,335
2011/12	1	2	-	-	10,960	1,623,825
2012/13	3	1	1	-	18,350	2,411,890
2013/14	4	3	-	1	45,391	8,357,485

*Note: 2005/06 and 2006/07 has been adjusted to include duration GSL payments for > 24 hour outages, despite these payment not commencing until 1 Jan 2007.

110 Note: (1) Where there is one MSWE with two consecutive MEDs then both days are assigned the same higher category. For example, if two consecutive MED with one meeting the USAIDI criteria for a Cat 1 and the other a Cat 2 then the MSWE would be classified as a Cat2 and both MEDs classified as Cat2 MEDs. (2) The significant range in the cost of LD GSL payments for Cat2 and 3 MSWE are generally dependent on whether the MSWE's impacts are localised or widespread. The higher costs are associated with more localised MSWEs where the damage to infrastructure is greater.

111 Cost is based on GSL payments amounts applicable to the 2010–15 RCP.

'Efficiency' of SA Power Networks' GSL payments on MEDs
The level of customer LD GSL payments is specified in the South Australian Electricity Distribution Code. As such, SA Power Networks has no control over the level of these payments, and cannot improve its efficiency in this respect.

The only sense in which SA Power Networks may take action to affect the amount of LD GSL payments it is liable for is by maintaining the reliability of the distribution network.

In order to demonstrate that the increase in MED-related GSL payments has not been due to a deterioration in overall network performance, SA Power Networks has conducted analysis of its performance over time on MSWE MEDs and SWE days not classified as MEDs.

As there were no Cat3 or Cat4 MSWE MEDs during the 2005–10 RCP, it is not possible to compare performance on those days between the 2005–10 and 2010–15 periods. It is also not possible to compare Cat2 MSWE MED performance, as the two Cat2 MEDs in 2005–10 were widespread in nature, compared to the Cat2 MEDs during 2010–15, the majority of which were more localised in nature.

It is however possible to compare Cat1 MSWE MED performance between the two periods as there is a statistically sufficient number of events to enable a valid comparison. Table 23.8 below compares the average daily USAIDI, and the number and cost of the LD GSL payments on Cat1 MSWE MEDs in the 2005–10 and 2010–15 periods. This comparison shows that the average USAIDI contribution in both periods has been identical at 6.1 minutes (ie Cat1 MEDs have been of a similar severity) and that the average number and cost of duration GSL payments per Cat1 MED have decreased between the 2005–10 and 2010–15 periods. This indicates that the increase in duration of GSL payments associated with Cat1 MSWE MEDs has not been due to deterioration in overall network performance — rather, this has been the result of an increase in the number of Cat2 and the emergence of Cat3 and 4 MSWE MEDs.

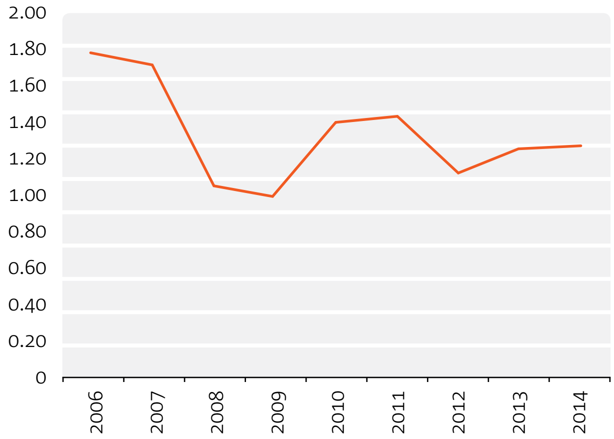
Table 23.8: Average daily USAIDI and duration GSL payments on Cat1 MSWE MEDs

RCP	Cat1 MEDs	USAIDI	No. GSLs	GSL ($)
2005–10	16	6.1	800	139,324
2010–15	11	6.1	641	105,072

SA Power Networks has also examined the average daily USAIDI contribution from days upon which the BoM has reported a SWE, but that SWE has not resulted in a MED. This analysis enables the determination of whether SA Power Networks has contributed to the decline in performance of MEDs or not. If the daily SAIDI contribution had a neutral or decreasing daily SAIDI then it could be concluded that SA Power Networks was appropriately maintaining the network and was not contributing to the increased numbers of GSL payments from MEDs.

Figure 23.1 below shows the average daily contribution to USAIDI from non-MED SWEs. This shows no increasing trend in daily USAIDI contribution on these days. This further demonstrates that SA Power Networks is not contributing to the increased number and cost of LD GSL payments on MEDs.

Figure 23.1: Average daily USAIDI contribution from SWE days that are not MEDs



Conclusion on duration GSL payments
The above analysis demonstrates that the increase in duration GSL payments has resulted from the significantly increased severity of MSWE MEDs (the average MED USAIDI more than doubled) in the 2010–15 RCP.

Clearly, the increase in LD GSL payments associated with MEDs[112] is beyond SA Power Networks' control. SA Power Networks cannot influence the incidence or severity of MEDs. Further, the above analysis of SA Power Networks' performance on severe weather days indicates that the increase in GSL payments associated with MEDs has not been due to a deterioration of network performance on these days.

As noted above, SA Power Networks is unique in being liable to pay GSLs arising from MEDs. If SA Power Networks was subject to the AER STPIS, it would not have incurred these additional uncontrollable GSL costs arising from MEDs.

SA Power Networks therefore proposes that LD GSL payments associated with MEDs be classified as uncontrollable costs for the purposes of the EBSS. These costs amount to $18.5 million over 2010/11 to 2013/14. Exclusion of this cost category from the operation of the EBSS would be consistent with clause 6.5.8(c) of the NER, which requires the EBSS to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure.

If GSL payments associated with MEDs[39] were to be included in the operation of the EBSS, this would lead to SA Power Networks being penalised for incurring costs in a category over which it has no control.

112 All MEDs during the 2010–15 regulatory control period have coincided with a BoM reported SWE.

Exclusion of this cost category would also be consistent with the factors set out in clause 6.6.1(j) of the NER. As noted above, the costs which SA Power Networks proposes to exclude are limited to those that are consequential on uncontrollable events. Further, the evidence presented above demonstrates that the increase in LD GSL payments in the current period has not been due to any inefficiency on the part of SA Power Networks.

Regulatory compliance costs

SA Power Networks has incurred costs of approximately $1.3 million in 2013/14 in complying with new regulatory requirements, particularly new RIN compliance requirements associated with recent changes to the Rules. These costs are uncontrollable, in the sense that they cannot be avoided or mitigated by SA Power Networks. Further, these costs were not accounted for in SA Power Networks' operating expenditure allowance for the 2010–15 RCP. These costs have arisen due to significant changes in the scope of SA Power Networks' regulatory compliance obligations.

Following the changes to the Rules which took effect in November 2012, the AER undertook its Better Regulation program, which involved publishing a series of new guidelines in November and December 2013. As part of the Better Regulation program, the AER published an expenditure forecast assessment guideline, which specifies (among other things) the information required by the AER to assess expenditure.

Following on from the issue of the expenditure forecast guideline, the AER has issued Regulatory Information Notices (RINs) to SA Power Networks, requiring it to provide extensive amounts of information relating to its physical assets, past expenditure, operating environment and various other aspects of its operations. Table 23.9 below summarises the information that SA Power Networks has been required to collect and provide to the AER in response to two RINs.

Table 23.9: RINs recently issued to SA Power Networks under Division 4 of Part 3 of the NEL

RIN	Description	Summary of information required	
RIN for economic benchmarking	This RIN comprises inputs, outputs and environmental factors involved in service delivery. It is intended to allow the AER to analyse the relative efficiency of NSPs over time and compared to their peers at an aggregated level.	This requires information on: • Revenue • Opex • Assets (RAB) • Operational data – Energy delivery – Customer numbers – Connection point numbers – Maximum Demand • Physical Assets • Quality of service issues • Operating environment factors – Vegetation management – Weather stations – Rural proportion – Other operating environment factors	Backcast data was required for eight years (2005/06–2012/13). Five years of this data (2008/09–2012/13) needed to be independently audited and reviewed. Audit and review reports must to be provided to the AER annually, together with a Statutory Declaration signed by the CEO.
RIN for category analysis	This RIN is intended to allow the AER to conduct benchmarking, trend and driver-based assessments at the disaggregated activity or expenditure category level.	This requires information on: • Demand forecasting – System level maximum demand – Spatial maximum demand • Augmentation capex – Augex model – Capex-capacity table • Replacement capex • Connections and customer-initiated – Connections – Public lighting – Metering – Fee-based and quoted services • Non-network expenditure • Vegetation management • Maintenance • Emergency response • Supply interruptions • Overheads • Labour and input costs	Backcast data for the Category Analysis RIN was required for 5 years. The RIN response must be independently audited and reviewed and audit and review reports must be provided to the AER. Subsequent year's data must be audited and lodged each October until 2024.

The extent of these regulatory information notices has resulted in over 700,000 cells of data being provided to the AER and significant additional costs being incurred to prepare the returns and to have them independently reviewed. These costs are uncontrollable, in the sense that they cannot be avoided or mitigated by SA Power Networks — the AER has served these RINs, and under the NEL, SA Power Networks must comply with these RINs.[113]

The operating expenditure allowances approved in the 2010 Determination included costs incurred to comply with the existing AER reporting requirements at the time. The extensive additional reporting requirements arising from the subsequent Better Regulation program clearly could not have been foreseen in the 2010 Determination process and are not costs that can be controlled or otherwise mitigated by SA Power Networks.

SA Power Networks has incurred incremental costs of $1.254 million in 2013/14 in complying with regulatory requirements, particularly RIN compliance requirements. These costs comprise:

- external Audit Fees $608,553
- external consultants $268,411
- external resources $129,225
- internal Resources $248,100 (engaged directly for RIN compliance)

Full details of these costs are provided in Attachment 23.8 to this Proposal.

Internal and external resource costs relate to resources recruited primarily to address RIN requirements. In addition, substantial existing staff resources from throughout the organisation have been diverted to prepare the reports. This diversion of resources has helped to mitigate the additional costs incurred, but at the expense of regular duties. These existing staff resource costs have not been included, however consultancy work sourced externally as a direct result of the unavailability of internal resources due to RIN reporting have been included.

Both the economic benchmarking and category analysis RINs allow for some data to be prepared on an estimated basis in the short term but requires actual data to be provided for all categories specified by 2014/15 for the economic benchmarking RIN and 2015/16 for the category analysis RIN. Additional internal costs have been incurred to identify the business requirements to report actual data. In future years further IT and internal resource costs will be incurred in implementing these changes.

SA Power Networks therefore proposes that the incremental regulatory compliance costs associated with complying with RINs recently issued in connection with the Better Regulation program be classified as uncontrollable costs for the purposes of the EBSS. Exclusion of this cost category from the operation of the EBSS would be consistent with clause 6.5.8(c) of the NER, which requires the EBSS to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure.

113 Section 28N of the NEL states that, on being served a regulatory information notice, a person named in the notice must comply with the notice.

Clearly SA Power Networks cannot avoid RIN compliance costs, as it simply must comply with these RINs under the NEL.

SA Power Networks has endeavoured to comply with the AER's RIN reporting requirements as efficient a manner as possible. As there was no allowance for these costs in the 2010 Determination, there is a clear incentive to minimise these costs as much as possible, whilst still meeting compliance requirements. External service providers have been competitively sourced, and where possible internal resources have been reassigned from other duties to minimise incremental costs.

Summary of Adjustments for other specific uncontrollable costs

SA Power Networks' expenditure in these two other uncontrollable cost categories in the first four years of the 2010–15 RCP is summarised out in Table 23.10 below.

Table 23.10: Expenditure in additional uncontrollable cost categories ($ million, nominal)

	2010/11	2011/12	2012/13	2013/14
Uncontrollable GSL costs	6.1	1.6	2.4	8.4
Regulatory compliance	-	-	-	1.3
Total	**6.1**	**1.6**	**2.4**	**9.6**

Summary of adjustments to actual operating expenditure

Actual operating expenditure for EBSS purposes is calculated by making each of the above adjustments to SA Power Networks' actual expenditure for each of the first four years of the current regulatory control period. This results in the amounts shown in Table 23.11.

Table 23.11: Calculation of operating expenditure for EBSS purposes

	2010/11	2011/12	2012/13	2013/14
Actual operating expenditure ($ million, nominal)	208.1	206.7	225.4	236.8
Adjustments for pass through events ($ million, nominal)*	-	-	(14.9)	(11.4)
Adjustments for excluded cost categories ($ million, nominal)**	(11.4)	(11.2)	(11.5)	(14.8)
Adjustments for other uncontrollable costs ($ million, nominal)***	(6.1)	(1.6)	(2.4)	(9.6)
Operating expenditure for EBSS purposes ($ million, nominal)	190.7	193.9	196.6	201.0
Operating expenditure for EBSS purposes (June 2015, $ million)	211.9	210.3	209.0	208.0

* Refer to Table 23.3.
** Refer to Table 23.4.
*** Refer to Table 23.10.

Benchmark allowance for the 2010–15 RCP
The benchmark operating expenditure allowance for EBSS purposes for the 2010–15 RCP was set out in Table 13.1 of the AER's 2010 Determination. This benchmark allowance is adjusted for the uncontrollable cost items identified by the AER in that determination and also includes an adjustment for the deferred carryover from the 2005–10 RCP.

Adjustment for feed-in tariff expenditure
An adjustment is required to the benchmark allowance set out in Table 13.1 of the AER's 2010 Determination, to account for the subsequent amendment to that determination relating to feed-in tariff payments.

In February 2012, the AER made a determination which had the effect of varying its original 2010 Determination.[114] The variations made included an adjustment to ETSA Utilities' operating expenditure allowance for each of the years 2011/12 to 2014/15 to remove projected feed-in tariff payments from this allowance.

The purpose of this variation was to allow feed-in tariff payments to be recovered through the annual pricing process, under new rules which commenced on 1 July 2010.[115]

Since 2011/12, feed-in tariff payments have been recovered by ETSA Utilities/SA Power Networks through the annual pricing process, in accordance with the jurisdictional scheme arrangements under the Rules. Accordingly, these payments are not included in SA Power Networks' operating expenditure for standard control services for each of the years 2011/12 to 2014/15, as set out in Table 23.14.

SA Power Networks therefore proposes to adjust the benchmark operating expenditure allowance for EBSS purposes for the 2010–15 RCP, to remove the allowance that was made for feed-in tariff payments in each of the years 2011/12 to 2014/15. This adjustment is consistent with the way in which these payments have been recovered since 2011/12 and with the AER's February 2012 variation determination to account for this revised treatment.

Table 23.12 below sets out the calculation of the adjusted benchmark allowance for EBSS purposes for the 2010–15 RCP.

Adjustment for MED-related duration GSL allowance
Consistent with SA Power Networks' proposal to exclude MED-related duration GSL payments from actual operating expenditure for the purposes of the EBSS, a corresponding adjustment has been made to the benchmark allowance.

Over the 2005 to 2010 period, 54% of GSL duration payments were made in relation to MED's. Accordingly the benchmark allowance has been reduced for EBSS purposes by 54% of the allowance made for GSL payments. As approximately $0.8 million per annum was allowed for GSL payments, this implies an adjustment of $0.43 million per annum.

Table 23.12 sets out the benchmark operating expenditure allowance for the current RCP, adjusted for feed-in tariff expenditure and MED-related GSL costs, as described above.

114 AER, Determination: ETSA Utilities application for revocation and substitution of 2010–11 to 2014–15 distribution determination — feed-in tariff payments, February 2012.

115 Specifically, clause 6.18.7A of the Rules, which commenced on 1 July 2010, set out a new cost recovery mechanism for 'jurisdictional scheme amounts'. Under the transitional rules relating to this new cost recovery mechanism, a business could elect to have it apply during the regulatory period in which the rule change took effect. The transitional rules provided revocation and substitution of distribution determinations to account for the application of this new cost recovery mechanism, where a business elected to have it apply during the regulatory period in which the rule change took effect. ETSA Utilities made this election, and accordingly the AER revoked its original distribution determination for the 2010–2015 regulatory control period and substituted a new distribution determination which accounted for the application of the new cost recovery mechanism from 2011/12 onwards.

Table 23.12: Adjusted benchmark operating expenditure allowance

	2010/11	2011/12	2012/13	2013/14	2014/15
Unadjusted benchmark allowance ($ million, June 2010)^	179.5	201.2	212.6	201.6	205.0
Adjustment to feed-in tariff payment allowance^^	-	(8.7)	(10.1)	(11.1)	(11.7)
Adjustment for MED-related GSL payments	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)
Adjusted benchmark allowance ($ million, June 2010)	179.0	192.0	202.0	190.0	192.8
Adjusted benchmark allowance (June 2015, $ million)^^^	202.3	216.9	228.2	214.7	217.8

^ AER, Final decision: South Australia distribution determination 2010–11 to 2014–15, May 2010, Table 13.1. Includes adjustment for opex carryover of $35.9 million.

^^ AER, Determination: ETSA Utilities application for revocation and substitution of 2010–11 to 2014–15 distribution determination — feed-in tariff payments, February 2012, Table 1.2.

^^^ Escalated by actual CPI for the four years to March 2014 plus estimate of CPI for the year to March 2015. Actual CPI will be applied in the revised proposal.

Calculation of carryover amounts

Incremental efficiency gains/losses for each year of the 2010–15 RCP are calculated in accordance with the EBSS Guideline.

For the first year of the 2010–15 RCP, the calculation is adjusted in accordance with the EBSS Guideline so as to only reflect incremental efficiency gains made in 2010/11. This is done by subtracting incremental efficiency gains made in the previous RCP after the base year (year 4 of the 2005–10 RCP).[116] This adjustment is consistent with providing a continuous incentive to reduce operating expenditure, as required by the Rules.[117] Table 23.13 below sets out this calculation.

Table 23.13: Efficiency saving for 2009/10

	2009/10
Allowance	151.9
Actual expenditure	154.3
Efficiency gain for 2009/10	(2.4)
Less cumulative efficiency gain/(loss) to 2008/09	(0.6)
Equals Incremental efficiency gain for 2009/10 ($M June 2010)	(3.1)
Incremental efficiency gain for 2009/10 ($M June 2015)	(3.5)

SA Power Networks' calculation of incremental efficiency gains/losses for each year of the 2010–15 RCP, and associated carryover amounts for the 2015–20 RCP, is set out in Table 23.14 below. The total carryover is $13.9 million.

Table 23.14: Calculation of carryover amounts for the 2015–20 regulatory control period ($ million June 2015)

Year	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Adjusted benchmark allowance†		202.3	216.9	228.2	214.7	217.8					
Actual operating expenditure for EBSS purposes††		211.9	210.3	209.0	208.0	211.2					
Efficiency saving/(loss)	(3.5)	(9.6)	6.6	19.2	6.7	6.7					
Incremental efficiency gain/(loss)		(6.1)	16.2	12.6	(12.6)						
Carry-over of gains made in 2010/11			(6.1)	(6.1)	(6.1)	(6.1)	(6.1)				
Carry-over of gains made in 2011/12				16.2	16.2	16.2	16.2	16.2			
Carry-over of gains made in 2012/13					12.6	12.6	12.6	12.6	12.6		
Carry-over of gains made in 2013/14						(12.6)	(12.6)	(12.6)	(12.6)	(12.6)	
Carry-over of gains made in 2014/15											
Total carry-over							**10.1**	**16.3**	**0.1**	**(12.6)**	

† Refer to Table 23.12.

†† Refer to Table 23.11. Actual operating expenditure for 2014/15 is estimated in accordance with the method set out in Section 2.3.1 of the AER's November 2008 EBSS — ie the estimate of actual operating expenditure for 2014/15 is based on the benchmark allowance for that year, less the efficiency saving/loss in the base year (in this case, year 4).

116 AER, Electricity distribution network service providers: Efficiency benefit sharing scheme, June 2008, Section 2.3.1; AER, Better Regulation: Efficiency benefit sharing scheme for electricity network service providers, November 2013, Section 1.3.2.

117 NER, clause 6.5.8(c)(2).

Treatment of negative carryover amounts

As shown above, SA Power Networks' calculation of carryover amounts from the 2010–15 RCP results in an overall net positive carryover. This calculation incorporates the deferred negative carryover from the 2005–10 RCP, meaning that this deferred negative carryover has reduced the magnitude of the positive carryover from the 2010–15 RCP, compared to what it would have otherwise been. SA Power Networks accepts that under the EBSS which has applied during the current period, the deferred negative carryover from the 2005–10 period can be used in this manner, to offset the positive carryover from the 2010–15 period.

However, we note that if the above analysis had resulted in an overall net negative carryover, this would need to be deferred to offset any positive carryover in the next regulatory period, to the extent that it is being driven by the inclusion of deferred negative amounts from the 2005–10 period. The reason for this is that, as recognised by the AER in establishing the EBSS for the current period, the deferred negative carryover from the 2005–10 period can only offset future positive carryovers.

As noted above, the AER's 2010 Determination stated that: "any negative opex carryover accrued under the current RCP Efficiency Carryover Mechanism can be deferred to offset any positive carryover accrued in the next RCP …"

The main reason for allowing this negative carryover to be deferred to offset future positive amounts was that the AER recognised that negative carryovers accrued under the ESCoSA scheme were at least partly accrued in connection with cost categories that would have been excluded under the AER's EBSS (ie uncontrollable cost categories). The AER recognised that due to several important differences between the ESCoSA scheme and the AER's EBSS — particularly the inclusion of uncontrollable costs in the ESCoSA scheme and provision for deferral of negative carryovers — a negative carryover should not be imposed on SA Power Networks, to the extent that that this was derived from applying elements of the ESCoSA scheme which are not part of the AER's EBSS.

It follows that the deferred negative carryover from the 2005–10 period must not be applied in the determination of carryover amounts from the 2010–15 RCP, if this results in an overall net negative carryover. To the extent that an overall net negative carryover results, the effect of the deferred negative carryover from the 2005–10 period must be removed from the calculation, and this amount once again deferred to offset any future positive carryover amounts.

23.2.6 Proposed application of the EBSS in the 2015–20 RCP

SA Power Networks supports continued application of the EBSS in the 2015–20 control period.

SA Power Networks also generally supports the AER's proposed approach to application of this scheme for the forthcoming period, as set out in the November 2013 EBSS Guideline, and the Framework and Approach Paper, subject to comments made below in relation to specific exclusions and adjustments.

Proposed excluded cost categories

SA Power Networks proposes to retain the same excluded cost categories that applied in the current RCP, for the purposes of applying the EBSS in the next RCP. Additionally, SA Power Networks proposes to exclude MED-related duration GSL payments from the operation of the EBSS in the next period.

As noted above, the following cost categories were excluded from the operation of the EBSS in the current RCP:

- debt raising costs;
- insurance and self-insurance costs;
- superannuation costs for defined benefits and retirement schemes; and
- the demand management innovation allowance (**DMIA**).

In deciding to exclude these cost categories from the operation of the EBSS, the AER noted that they are beyond the control of DNSPs. The AER considered that it was not appropriate for DNSPs to receive benefits or penalties through the EBSS for variances in its operating expenditure for cost categories over which they have no control. The AER observed that exclusion of these cost categories was therefore consistent with clause 6.5.8(c)(2) of the Rules which requires the EBSS to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure.[118]

For the reasons given by the AER, SA Power Networks proposes to exclude these same cost categories from the operation of the EBSS for the next period. These costs continue to be uncontrollable in nature, and therefore it would not be appropriate for SA Power Networks to receive benefits or penalties through the EBSS for variances in its operating expenditure in these cost categories.

Additionally, and for the same reasons, SA Power Networks proposes to also exclude MED-related duration GSL payments. As discussed above (section 23.2.5), the timing and quantum of these payments is entirely uncontrollable, and therefore it would not be appropriate for SA Power Networks to receive benefits or penalties through the EBSS for variances in its operating expenditure associated with variance in these payments.

AER position on exclusion of uncontrollable cost categories in the November 2013 EBSS Guideline

SA Power Networks notes that in the explanatory statement accompanying its November 2013 EBSS Guideline, the AER has indicated that it will not exclude costs from the EBSS on the grounds of uncontrollability. The AER acknowledges that under this approach the EBSS will reward or penalise DNSPs for some forecasting error associated with uncontrollable events, but then observed that on the whole, the risk of uncontrollable events presents both upside and downside risk to NSPs. The AER states that "*we do not think there is a compelling argument to share the cost of uncontrollable events differently to all other costs facing NSPs*".[119]

118 AER, *Draft Decision: South Australia Draft distribution determination 2010–11 to 2014–15*, 25 November 2009, pp 373–375.

119 AER, *Better Regulation — Explanatory Statement: Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, pp 25–27.

This represents a significant shift in the AER's position on exclusion of uncontrollable costs. As noted above, the AER has previously considered that it was not appropriate for DNSPs to receive benefits or penalties through the EBSS for variances in its operating expenditure for cost categories over which they have no control, and has noted that exclusion of these cost categories is therefore consistent with the requirements of the Rules.[120]

SA Power Networks is concerned that the AER's new approach will lead to DNSPs being rewarded or penalised through the EBSS for variances in operating expenditure that are outside of their control. This would not be consistent with providing DNSPs with a continuous incentive to reduce operating expenditure, as required by the Rules.[121]

The fact that variances in uncontrollable costs may be either on the 'upside' or 'downside' does not mean that uncontrollable costs should not be excluded. In either case there would be a reward or penalty accruing to the DNSP for variances in operating expenditure that are outside of its control.

This is illustrated by the very significant increases in SA Power Networks' MED-related duration GSL payments in the current RCP. As discussed in Section 23.2.5, these increases in GSL payments have been associated with uncontrollable extreme weather events, and have not been due to any inefficiency on the part of SA Power Networks. However under the AER's proposed approach of not excluding costs from the EBSS on the grounds of uncontrollability, SA Power Networks would incur significant financial penalties under the EBSS if the rate of increase in uncontrollable extreme weather events continued in the next RCP.

SA Power Networks therefore submits that the AER should depart from the position in its November 2013 EBSS Guideline in establishing the EBSS to apply to SA Power Networks for the next RCP. Specifically, the AER should exclude the uncontrollable cost categories referred to in Table 23.15 below from the operation of the EBSS for the next period. This would be consistent with the requirement of the Rules, that DNSPs be provided with a continuous incentive to reduce operating expenditure.

Table 23.15: Proposed exclusion cost categories (June 2015, $ million)

	2015/16	2016/17	2017/18	2018/19	2019/20
Debt raising costs	4.8	5.1	5.4	5.7	6.0
Network insurance	3.4	3.6	3.8	4.0	4.3
Self-insurance	2.1	2.2	2.2	2.3	2.4
Superannuation costs for defined benefits and retirement schemes	2.0	2.0	2.0	2.0	2.0
DMIA	0.6	0.6	0.6	0.7	0.7
Non network alternatives	0.2	0.2	0.3	0.3	0.4
Major Event Day GSL Payments	8.0	8.2	8.4	8.6	8.9
Total	**21.0**	**21.8**	**22.7**	**23.6**	**24.5**

23.3

Service Target Performance Incentive Scheme (STPIS)

The AER's national STPIS scheme[122] 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 GSL component whereby customers are paid directly if they experience service below a predetermined level.

During the 2010–15 RCP, SA Power Networks has been subject to a variant of the national STPIS scheme. The current scheme operating for SA Power Networks:

- has a maximum financial penalty or reward of ± 3% of annual revenue;
- incorporates USAIDI and USAIFI[123] supply reliability targets in four broad feeder categories (CBD, Urban, Rural Short and Rural Long);
- incorporates a telephone response customer service target;
- uses the four prior consecutive years average actual performance to calculate targets;
- uses the "Box-Cox" method for calculating a threshold, T_{MED}, for determining Major Event Days (**MEDs**) which are excluded from the reliability performance measure; and
- does not include the AER's GSL component as SA Power Networks is subject to the jurisdictional GSL scheme set by ESCoSA.

120 AER, *Draft Decision: South Australia Draft distribution determination 2010–11 to 2014–15*, 25 November 2009, pp 373–375.
121 NER, clause 6.5.8(c)(2).

122 AER, Electricity distribution network service providers — Service target performance incentive scheme", November 2009
123 USAIDI = unplanned system average interruption duration index, USAIFI = unplanned system average interruption frequency index

In its F&A for the 2015–20 RCP, the AER proposes to apply the national STPIS scheme to SA Power Networks but not apply the GSL component.[124] The key changes being proposed are therefore:

- Increasing the revenue at risk to up to ± 5% of annual revenue;
- Setting performance targets based on actual average performance in the previous five years; and
- Applying the national "natural logarithm" methodology (not Box-Cox methodology) to determine T_{MED}.

Changes to the jurisdictional service standards to apply in the 2015–20 RCP, outlined in Section 7.2.1, ensure there is now consistency between the parameters of the STPIS and the jurisdictional service standards.

23.3.1 Reliability targets

The alignment to the national scheme will alter which days are classified as MEDs. Under the Box-Cox methodology the number of MEDs for SA Power Networks is approximately 5 days per annum. Using the natural logarithm methodology, the number of MEDs will be approximately 2.5 days per annum — around half the number of days currently determined.

The change in how a particular day is classified as a MED will create a misalignment when calculating targets for not only the 2015–20 RCP but also the 2020–25 RCP. This is because targets set for the upcoming RCP will be based on the most recent five years actual performance which will span both the current and previous RCPs.[125]

To ensure SA Power Networks is not advantaged or disadvantaged in moving to the national methodology, we propose recalculating the actual performance of the 2010–15 RCP using the national scheme's method for calculating T_{MED} and adjusting each year's performance by an amount which achieves the equivalent revenue at risk that would otherwise be provided by the current STPIS regime.

Attachment 23.13 provides further detailed analysis quantifying the transitional issues in moving from the Box-Cox methodology to the natural logarithm methodology.

The proposed STPIS reliability targets for 2015–20 are outlined in Table 23.15.

Table 23.15 Proposed STPIS Reliability Targets for 2015–20

Reliability Target	CBD	Urban	Short Rural	Long Rural
SAIDI (minutes)	12.5	121.5	231.1	311.7
SAIFI (interruptions)	0.132	1.353	1.930	2.027

124 F&A, p14

125 That is, STPIS targets for the 2015–20 RCP are likely to be based on actual performance of four years from the 2010–15 RCP and one year from the 2005–10 RCP. Targets for the 2020–25 RCP will be based on actual performance of four years from the 2015–20 RCP and one year from the 2010–15 RCP.

In addition, SA Power Networks proposes that catastrophic event days[126] (**CEDs**) should be excluded from the calculation of T_{MED} to ensure SA Power Networks is not penalised for an event beyond its control. SA Power Networks has undertaken analysis which demonstrates:

- in recent years its network is experiencing more severe weather; and
- impact this has on T_{MED} calculations and STPIS outcomes.

This analysis is provided in Attachment 23.14.

To exclude CEDs from the calculation of T_{MED}, SA Power Networks proposes adding the following new sub-clause (8) to the list of excluded events in clause 3.3 of the AER's STPIS Guideline:

(8) load *interruptions* that commence on a *catastrophic event day.*

The following new definition of a CED would be included in the Guideline's Glossary:

> **Catastrophic event day** *Any day where the daily SAIDI exceeds a pre-determined value or methodology to determine the value as agreed between the AER and the DNSP. Note: The DNSP will propose the value or methodology for determining the SAIDI threshold for the AER's approval.*

If this change is not made prior to the commencement of the next RCP, and a CED(s) occurs in the RCP, an application from a DNSP for exclusion of the CED(s) should be permitted within a RCP.

23.3.2 Customer service targets

The STPIS customer service target applicable to SA Power Networks is telephone response measured as the number of telephone calls answered within 30 seconds. This measure is referred to as the telephone Grade of Service (**GOS**).

As permitted by the STPIS Guideline, MED telephone response is excluded from the telephone GOS. As with STPIS reliability target setting, a misalignment of GOS target setting between RCPs will also arise as a consequence of the change to how MEDs are classified and the overall reduction in the number of MEDs.

Also, SA Power Networks has recently become aware that we have not been reporting telephone responsiveness in accordance with the definitions contained in the STPIS Guideline. The 2010–15 RCP STPIS targets were set on the same methodology used to report our telephone responsiveness but this was the methodology used in the 2005–10 RCP, under the previous ESCoSA telephone response incentive regime, not the methodology in the AER's Guideline.

SA Power Networks proposes to address both these matters by adjusting the targets for the 2015–20 RCP to reflect the incentive received and report telephone GOS in accordance with the AER's STPIS Guideline.

126 Catastrophic event days are defined as days contributing more than 24 minutes to the USAIDI index

Attachment 23.13 summarises the relevant calculations. The proposed STPIS customer service target (GOS) for 2015–20 RCP is in Table 23.16 below.

Table 23.16: Proposed Customer Service Target for 2015–20

	GOS
STPIS target	67.8%

23.4

Demand Management Incentive Scheme (DMIS)

This section sets out SA Power Networks' proposal in relation to the application of the Demand Management Incentive Scheme (**DMIS**).

23.4.1
Rule requirements

The NER require the AER to develop and implement mechanisms to incentivise distributors to consider economically efficient alternatives to building more network.

Clause 6.6.3 of the NER sets out the factors that the AER must have regard to in implementing a DMIS.

23.4.2
Demand Management Incentive Allowance (DMIA)

Demand management refers to any effort by a distributor to lower or shift the demand for Standard Control Services. Demand management that effectively alleviates network utilisation during peak usage periods can be an economically efficient way of deferring the need for network augmentation.

A DMIS has applied to SA Power Networks in the current RCP. The current scheme includes a DMIA, a capped allowance to investigate and conduct broad-based and/or peak demand management projects. It contains two parts:

- Part A provides for an innovation allowance; and
- Part B compensates for any foregone revenue demonstrated to have resulted from demand management initiatives.

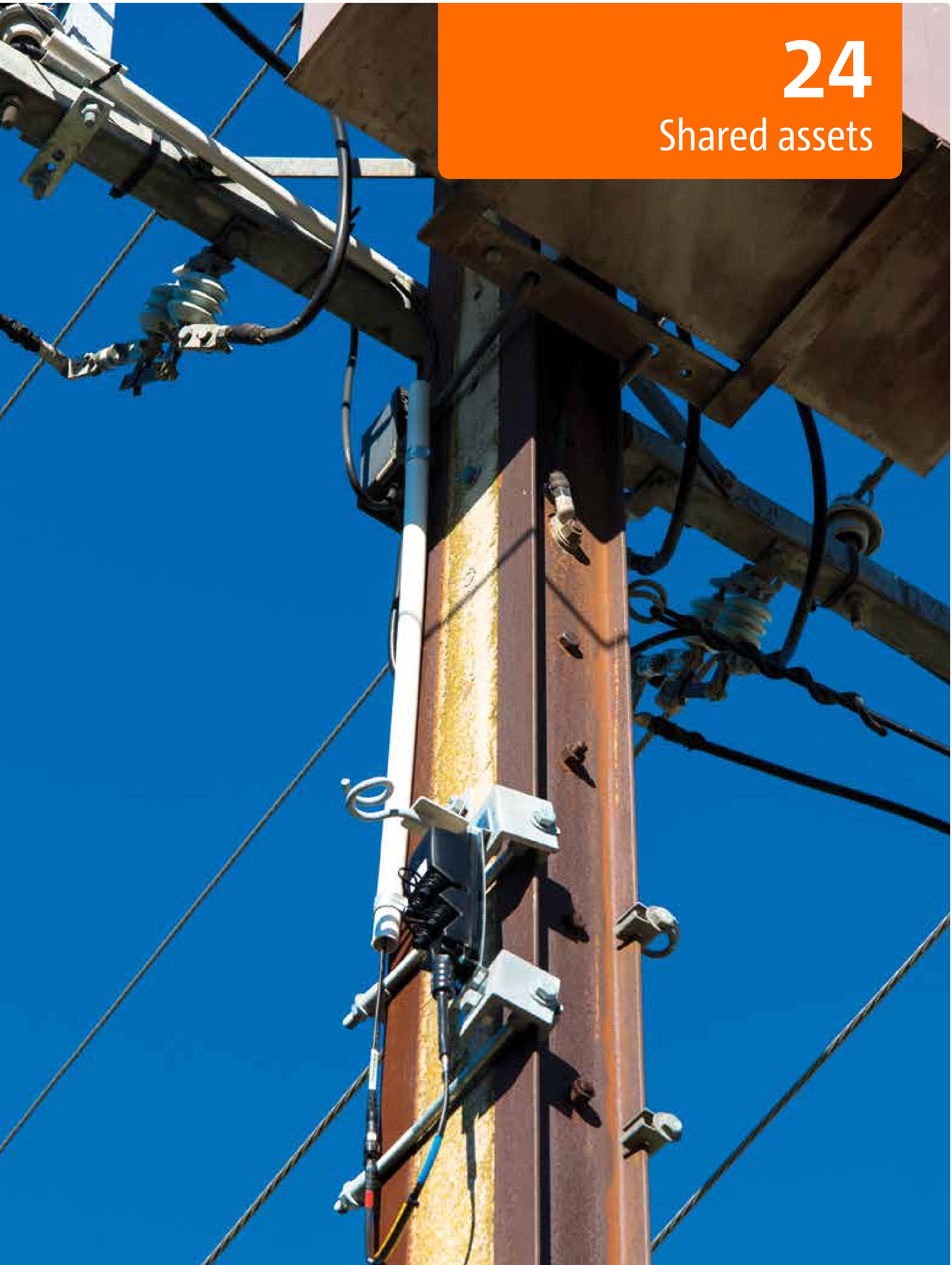
In its Framework and Approach paper, the AER has expressed its position to continue to apply the DMIS in the next RCP.[127] Part B will no longer apply as the AER will be adopting a revenue cap form of control.

SA Power Networks supports the AER's position to continue with the DMIA and the proposed amount of $600,000 each year in the next RCP and has included this level of DMIA in our Proposal.

We note however the AER's comments in relation to the current consideration of NER changes[128] as proposed by the AEMC.[129] These changes could result in the design of a new DMIS. SA Power Networks will be keen to engage early with the AER in any discussions on proposed changes to the DMIS and in the application and timing of any new scheme.

127 AER, Final framework and approach for SA Power Networks, April 2014, p67
128 SCER, Demand side participation — proposed rule changes, 18 September 2013
129 AEMC, Final report, Power of choice review — giving consumers choice in the way they use electricity, 30 November 2012

24 Shared assets



24

24.1

SA Power Networks' shared assets proposal

In accordance with paragraph 2.4 of the Shared Asset Guideline, SA Power Networks' has provided a proposal for shared asset cost reductions for the AER's approval.

24.2

Rule requirements

24.2.1 National Electricity Rules

Where an asset is used to provide both standard control services and unregulated services, NER 6.4.4 allows the AER to reduce SA Power Networks' standard control services 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.

NER 6.4.4 requires the AER to have regard to the shared asset principles. These principles are:

- SA Power Networks should be encouraged to use assets that provide standard controls services for other services where that use is efficient and does not materially prejudice the provision of standard control services;
- a cost reduction should not be dependent on SA Power Networks deriving a positive commercial outcome from the use of the asset other than for standard control services;
- a cost reduction should be applied where the use of the asset other than for standard control services is material;
- regard should be had to the manner in which costs have been recovered or revenues reduced in respect of the relevant asset in the past and the reasons for adopting that manner of recovery or reduction;
- any cost reduction should be compatible with the Cost Allocation Principles and Cost Allocation Method (**CAM**); and
- any reduction should be compatible with other incentives.

24.2.2 Shared Asset Guideline

NER 6.4.4 also requires the AER to make Shared Asset Guidelines and to have regard to the Shared Asset Guidelines in determining shared asset cost reductions.

The AER published a Shared Asset Guideline (**Guideline**) in November 2013. The Guideline sets out the detailed mechanism the AER will apply for shared asset cost reductions. The AER may vary its approach from the Guideline only if it explains its reasons for doing so. Together, the NER shared asset provisions and the Guideline establish the shared asset mechanism.

The Guideline states that[130]:

- the AER may make cost reductions in advance for each year unregulated revenues earned from shared assets are expected to exceed 1% of standard control services revenue;
- the AER will determine cost reductions using the methods set out in the Guideline;
- the AER will reduce standard control Service revenues by the amount of cost reduction determined; and
- the AER will consider alternative cost reduction methods if the result leaves consumers no worse off than the method in the Guideline.

Paragraph 2.4.a of the Guideline states that service providers may include in a regulatory proposal for a regulatory period proposed cost reductions for the AER's approval.

The shared asset cost reduction methodology set out in the Guideline is as follows, for each year of the RCP:

- determine the proposed standard control services annual revenue requirement (**ARR**);
- determine the forecast shared asset unregulated revenue (**SAUR**);
- determine whether SAUR is greater than 1% of the ARR;
- where the SAUR is greater than 1% of the ARR, calculate the shared asset cost reduction (10% of the SAUR);
- adjust the shared asset cost reduction for the value to standard control services customers of contributed assets (if any);
- estimate the control value (the sum of return on and return of capital for shared assets); and
- if the shared asset cost reduction exceeds the control value, reduce the shared asset cost reduction to the control value.

Materiality and unregulated revenue relevant to cost reductions are determined by averaging expected SAUR across each regulatory year to which those revenues relate.

24.2.3 Regulatory Information Notice requirements

The regulatory information notice (**RIN**) served on SA Power Networks on 25 August 2014 requires SAUR data for each service to be provided in RIN data template 7.4. The template has been completed and provided to the AER with this Proposal.

130 AER, Shared Asset Guideline, paragraph 1.5

24.3

Proposed annual revenue requirement

SA Power Networks' proposed annual revenue requirement for standard control services for each year of the next RCP is set out in Table 24.1.

Table 24.1: Proposed annual revenue requirement 2015–20

	2015/16	2016/17	2017/18	2018/19	2019/20
Annual smoothed revenue requirement (Nominal $m)	901.8	924.8	948.4	972.6	997.4

24.4

Forecast average shared asset unregulated revenue

SA Power Networks' forecast average SAUR for each year of the next RCP is set out in Table 24.2.

Table 24.2: Forecast shared asset unregulated revenue 2015–20

	2015/16	2016/17	2017/18	2018/19	2019/20
Average SAUR (Nominal $m)	9.6	9.6	9.6	9.6	9.6

SA Power Networks' SAUR includes revenue apportionment in respect of services that use shared assets only minimally. The methodology used for the forecast of SA Power Networks' SAUR, including revenue apportionment, is set out in Section 24.8 of this chapter. The detailed assumptions and worked methodology are set out in the Shared Asset Cost Reduction Method in Attachment 24.2.

24.5

Materiality assessment

The Guideline states that the AER will consider the unregulated use of shared assets in a regulatory year to be material when a service provider's annual SAUR is expected to be greater than 1 per cent of its total smoothed ARR for that regulatory year.[131]

SA Power Networks' assessment of the materiality of SAUR for each year of the next RCP is set out in Table 24.3.

Table 24.3: Materiality assessment

	2015/16	2016/17	2017/18	2018/19	2019/20
Average SAUR as a proportion of ARR (%)	1.07%	1.04%	1.02%	0.99%	0.97%
Material (Y/N)	Y	Y	Y	N	N

24.6

Proposed shared asset cost reduction

Forecast SAUR exceeds the guideline materiality threshold in the first three years of the next RCP.

SA Power Networks' proposed gross shared asset cost reduction (**SACR**) for each year of the next RCP is set out in Table 24.4.

Table 24.4: Proposed shared asset cost reduction 2015–20

	2015/16	2016/17	2017/18	2018/19	2019/20
SACR (Nominal $m)	0.963	0.963	0.963	-	-

The methodology used for the determination of SA Power Networks' proposed shared asset cost reduction is set out in Section 24.9 of this chapter.

24.7

Control step cap value

The Guideline states that service providers may report their estimate of the sum of return on and return of capital in respect of their shared assets, because under the NER, the shared asset cost reduction may not exceed this value.

SA Power Networks has not reported an estimate of the standard control services revenues it expects to earn from shared assets. SA Power Networks does not expect the shared asset cost reduction to exceed the total return on and of capital in respect of shared assets in any year.

SA Power Networks acknowledges that the AER may make its own estimate of a control step cap value where a service provider does not provide an estimate.

131 AER, Shared Asset Guideline, paragraph 2.3b

24.8

Shared asset unregulated revenue proposed methodology

24.8.1 Requirements and guidance

The Guideline defines SAUR as revenue paid to a distributor for unregulated services provided using the distributor's shared assets. Shared assets are those assets that are used to provide both standard control and unregulated services. However the shared asset mechanism only applies to shared assets where the allocation of the costs of establishing the assets overstates the current use of the assets for standard control services.

The Guideline states that where a service uses shared assets to a minimal extent relative to all the assets used by that service, the AER may accept revenue apportionment in respect of that service[132]. Revenue apportionment means proportionately reducing the total unregulated revenue earned from a specific unregulated service to reflect the extent of shared asset use by that service. The AER provided further guidance in respect of revenue apportionment in the Explanatory Statement to the Shared Asset Guideline[133] and the Explanatory Statement to the Draft Shared Asset Guidelines.[134] Here the AER recommends that in such cases service providers focus on the unregulated revenue stream derived from an unregulated service, and apportion unregulated revenues to reflect the extent to which unregulated services rely on shared assets.

Where services make an insignificant use of shared assets and the proposed apportionment reasonably reflects shared asset use, the AER will accept it as an element of their cost reduction determination. Service providers proposing revenue apportionment must submit to the AER:

- the rationale for proposing apportionment;
- the proposed apportionment; and
- the method used to determine that apportionment.

Service providers should submit sufficient information for the AER to replicate the proposed apportionment using the service provider's method.

24.8.2 Rationale

SA Power Networks believes that it is crucial for the AER to allow a reasonable apportionment of unregulated services revenue in the estimation of shared asset unregulated revenue to give effect to NER 6.4.4(c)(1) and (3).

It should be noted that the application of the guideline poses risks to standard control services customers as well as service providers. If the shared asset cost reduction methodology causes service providers to choose not to provide efficient services, or to provide services by means that avoid the use of regulated assets, much of the benefits to standard control services of sharing corporate operating costs with unregulated services will be lost.

132 AER. Shared Asset Guideline, paragraph 2.6
133 Better Regulation, Explanatory statement, Shared Asset Guideline, AER, November 2013, p35.
134 Better Regulation, Explanatory statement, Draft Shared Asset Guidelines, AER, July 2013, p32.

This is an important matter for SA Power Networks. We provide a variety of unregulated services, and these services' use of shared assets varies widely. For example, one of the unregulated services SA Power Networks provides is pole rental for telecommunications purposes. The organisation's ability to provide this service is clearly dependent on the existence of the relevant poles, the costs of which would be expected to be reflected in the regulated asset base. The revenue recovered by providing such a service clearly reflects the service's dependence on regulated assets.

This type of service can be contrasted with services that are not at all dependent on the use of regulated assets. An example is the construction of electrical infrastructure for commercial clients in a highly competitive market. This service is essentially one of project management, where varying but most often significant components of labour, services, plant and equipment, and materials are outsourced, subcontracted or even passed through, but all of these costs are reflected in revenue.

SA Power Networks provides several services generating significant revenue in this way, a growing proportion of which are provided from locations outside of South Australia and are unrelated to SA Power Networks' distribution network. The use of regulated assets in the provision of such services varies between services and fluctuates over time and is therefore difficult to determine, but it is intuitively insignificant. Equipment utilisation is a small proportion of the service, and such equipment can easily be (and often is) leased. Such services clearly do not rely on the use of regulated assets. It is also clear that the gross revenue earned by the provision of such services is unrepresentative of such services' use of any regulated assets.

NER 6.4.4(a) provides that the AER may reduce the ARR by an amount it considers reasonable to reflect the costs of a shared asset the service provider is recovering by charging for an unregulated service. The AER has recommended that service providers focus on the revenue stream of unregulated services, and the extent to which they rely on shared assets. SA Power Networks has therefore developed a methodology for the estimation of SAUR that includes the apportionment of revenue from unregulated services that do not rely on the use of shared assets.

24.8.3 Methodology

SA Power Networks' methodology for the estimation of SAUR involves 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' uses the allocation apportioned by its approved CAM to derive those revenues.

SA Power Networks has developed a simple and transparent method for the apportionment of revenue from this second class of unregulated services that is consistent with the Guideline and with the shared asset requirements and principles set out in the NER.

SA Power Networks has based its apportionment methodology on the shared assets used by each service, and made it appropriate for application to non-asset dependent unregulated services in a consistent manner.

SA Power Networks' methodology for the estimation of SAUR, including revenue apportionment, is set out in Table 24.5.

Table 24.5: SAUR proposed methodology 2015–20

Step	Outline of SA Power Networks' proposed methodology
1.	Identify all unregulated services.
2.	Identify unregulated services that use shared assets (shared asset unregulated services) by reference to the assets used to deliver the service and how those assets' establishment costs were allocated.
3.	Consider and classify each shared asset unregulated service as either shared asset dependent (shared asset dependent services) or using shared assets only marginally (marginal shared asset services). The classification is made by reference to each service's relative use of shared assets (the shared asset proportion), which is based on how revenue is actually recovered.
4.	Estimate the average gross revenue expected to be derived from each shared asset unregulated service for each relevant year of the next RCP.
5.	Calculate SAUR for each year of the next RCP. This is comprised of the sum of: • the sum of the average revenue expected to be derived from each shared asset dependent service; and • the sum-product of the average revenue expected to be derived from each marginal shared asset service and its relevant shared asset proportion.

The results of this methodology are set out in Table 24.2.

SA Power Networks believes that the above methodology is appropriate for its intended purpose. It is functionally simple and focuses on revenue. It reasonably reflects the recovery of asset costs via the revenue from unregulated services as it is consistent with SA Power Networks' derivation of unregulated revenue.

24.9

Shared asset cost reduction methodology

In accordance with paragraphs 3.1.d. and 3.4 of the Guideline, the SACR proposed by SA Power Networks is 10 per cent of the shared asset unregulated revenue estimated for each year of the next RCP by the method described in Table 24.5 and shown in Table 24.4, adjusted to reflect the value of electricity consumer benefits accruing from third party initiated network improvements.

The provision of unregulated services and negotiated distribution services to specific third party customers can sometimes necessitate the earlier improvement of parts of the distribution network than would otherwise have been the case. For example, some power poles require reinforcement or replacement in order to be able to support the additional load from lighting assets or telecommunications cable. The customers that wish to benefit from the supplementary use of power poles are required to pay for these early improvements, which provide a saving to electricity distribution customers.

SA Power Networks has estimated the benefit to electricity distribution customers of third party funded network improvements over the next RCP. The benefit has been valued as the present value of the avoided cost resulting from early improvements. The methodology used to estimate the benefit to electricity distribution customers of third party funded network improvements over the next RCP is set out in Attachment 24.2.

SA Power Networks' gross shared asset cost reduction, the proposed consumer benefits accruing from third party initiated network improvements, and the proposed net shared asset cost reduction for each year of the next RCP are set out in Table 24.6.

Table 24.6: Proposed shared asset cost reduction methodology 2015–20

	2015/16	2016/17	2017/18	2018/19	2019/20
Gross SACR: 10% of SAUR (Nominal $m)	0.963	0.963	0.963	-	-
Less: Electricity consumer benefits (Nominal $m)	(0.142)	(0.142)	(0.142)	(0.142)	(0.142)
Net shared asset cost reduction (Nominal $m)	0.821	0.821	0.821	-	-
Net shared asset cost reduction ($2015)	0.800	0.780	0.761	-	-

25
Regulated Asset Base

25

In this chapter of the Proposal, SA Power Networks presents the methodology it has applied in calculating its regulated asset base (**RAB**), comprising system and non-system assets utilised in the provision of standard and alternative control services.

The methodology applied is in accordance with the National Electricity Rules (**Rules**) and utilises the AER's Roll Forward and Post Tax Revenue Models.

The completed models are provided as Attachments 25.1 and 25.2 to this Proposal.

25.1

Regulatory requirements

The Rules at clause 6.5.1 describe the nature of the regulatory asset base for standard control services. It requires the AER to develop and publish a model for the roll forward of the regulatory asset base and provides the requirements for the roll forward model.

Schedule 6.1.3(7) requires a building block Proposal to contain a calculation of the RAB for each regulatory year, using the roll forward model, 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 Rules; 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.

Schedule 6.1.3(10) requires a building block Proposal to contain a completed Post Tax Revenue Model and Roll Forward Model.

Other provisions relating to the regulated asset base are set out in Schedule 6.2. In particular:

- subclause 6.2.1(e) specifies the method of adjustment of value of the RAB between regulatory periods; and
- subclause 6.2.3 specifies the method of adjustment of value of the RAB for each regulatory year within a RCP.

25.2

Roll forward of the RAB value from 1 July 2010 to 30 June 2015

25.2.1
Methodology used to roll forward the RAB value

SA Power Networks has applied the methodology set out in Schedule 6.2 of the Rules and has used the AER's Roll Forward Model.

As required by clause 6.5.5(b)(3) of the Rules, depreciation has been applied using the same prime cost methodology and same asset lives as applied in the 2010 Determination.

The roll forward of the RAB to 1 July 2015 will utilise actual depreciation, in accordance with the 2010 Determination.

25.2.2
Assumptions applied to the RAB roll forward

SA Power Networks has made a number of assumptions in the roll forward of the RAB to 1 July 2015.

Adjustment for Inflation

The RAB has been indexed each year in a manner consistent with the annual price adjustments in the current RCP. Indexation of the RAB for the years ended 30 June 2011 to 30 June 2015 has been determined by applying the actual All Groups CPI, Weighted Average of Eight State Capital Cities (published by the Australian Bureau of Statistics) for the years to 31 March 2011 to 2015 respectively.

At the time of preparing this Proposal, actual inflation data for the 2015 regulatory year is not available. The roll forward will be adjusted in the Revised Proposal to reflect actual 2015 data.

Disposals of assets

Asset disposals largely comprise assets, such as vehicles, land and buildings. Asset disposals are recognised in the year of disposal, with the proceeds deducted from the RAB.

Assumptions for the 2014 and 2015 Regulatory Years

At the time of preparing this Proposal, actual data for the 2014 and 2015 regulatory years for capital expenditure, depreciation and asset disposals is not available. Unaudited capital expenditure and asset disposal data for the 2014 regulatory year has been applied in this Proposal, with depreciation calculated accordingly. The roll forward will be adjusted in the Revised Proposal to reflect actual 2014 data. The actual data for 2015 will not be available for the AER's final determination. Therefore the roll forward has applied the current RCP's capital expenditure allowance for 2015. The difference between this amount and the actual amount will be reflected in the roll forward of the RAB to 1 July 2020.

25.2.3
Adjustment for actual capex for 2009/10

In accordance with Schedule 6.2.1(e), the RAB balance at 30 June 2015 is required to incorporate an adjustment for the difference between the estimated capex for 2009/10 incorporated into the 2010 Determination and the actual capex for 2009/10.

This adjustment is calculated in the AER's Roll Forward Model and is summarised in Tables 25.1 and 25.2.

25.2.4
Roll forward of the RAB value from 1 July 2010 to 30 June 2015

The roll forward for SA Power Networks' RAB over the current RCP from 1 July 2010 to 30 June 2015 is summarised in Tables 25.1 and 25.2.

These calculations are extracted from a completed version of the AER's Roll Forward Model. The closing RAB value at 30 June 2015 forms the opening RAB for the roll forward of the RAB from 1 July 2015 to 30 June 2020.

Table 25.1: Standard Control Services RAB roll forward to 2015 ($ million, nominal)

	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	362.0
Less regulatory 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	73.5
Difference between actual and forecast capex for 2009/10					(38.6)
Closing RAB	3,096.8	3,287.9	3,502.0	3,674.4	3,829.4

Table 25.2: Alternative Control Services RAB roll forward to 2015 ($ million, nominal)

	2010/11	2011/12	2012/13	2013/14	2014/15
Opening RAB	80.7	81.7	81.1	80.7	80.0
Plus capital expenditure, net of contributions and disposals	4.0	4.2	4.2	3.8	13.6
Less regulatory depreciation	(5.7)	(6.1)	(6.5)	(6.9)	(7.4)
Plus nominal actual inflation on opening RAB	2.7	1.3	2.0	2.4	1.6
Difference between actual and forecast capex for 2009/10					(2.4)
Closing RAB	81.7	81.1	80.7	80.0	85.4

25.3

Roll forward of the RAB value from 1 July 2015 to 30 June 2020

25.3.1
Methodology used to roll forward the RAB value

SA Power Networks has modelled the roll forward of the RAB for the next RCP based on the closing RAB value as at 30 June 2015, as detailed in Section 25.2 above.

SA Power Networks has applied the methodology set out in Schedule 6.2 of the Rules and has used the AER's Post Tax Revenue Model.

Forecast capital expenditure has been applied, as detailed in Chapter 20 of this Proposal. Depreciation has been calculated on a straight line basis, using asset lives as provided in Chapter 27. Forecast asset disposals have been incorporated.

25.3.2
Assumptions and adjustments applied to the RAB roll forward

SA Power Networks has made a number of assumptions and adjustments in the roll forward of the RAB to 1 July 2020:

- an inflation rate has been assumed, which is consistent with the rate used for the WACC.
- the balance of Work in Progress at 30 June 2015 will be allocated to the asset categories to which the expenditure relates, so as to transition to depreciation on an 'as incurred' basis. This adjustment is made to be consistent with the AER's standard methodology. The allocation of the opening balance of work-in-progress at 1 July 2015 has been estimated based on the average mix of capital expenditure from 2010/11 to 2013/14 year. This estimate will be updated in the Revised Proposal based on an updated forecast of work-in-progress at 30 June 2015. Differences between this forecast and the actual 30 June 2015 balances will subsequently be reflected in the Roll Forward Model for 2015 to 2020.
- forecast contributions from 1 July 2015 will be allocated against their relevant asset class, not the contributions asset category, as described in Chapter 27.

25.3.3
RAB roll forward to 30 June 2020

The projected RAB at the end of each year over the next RCP is summarised in Tables 25.3 and 25.4.

Table 25.3: Standard Control Services RAB roll forward to 2020 ($ million, nominal)

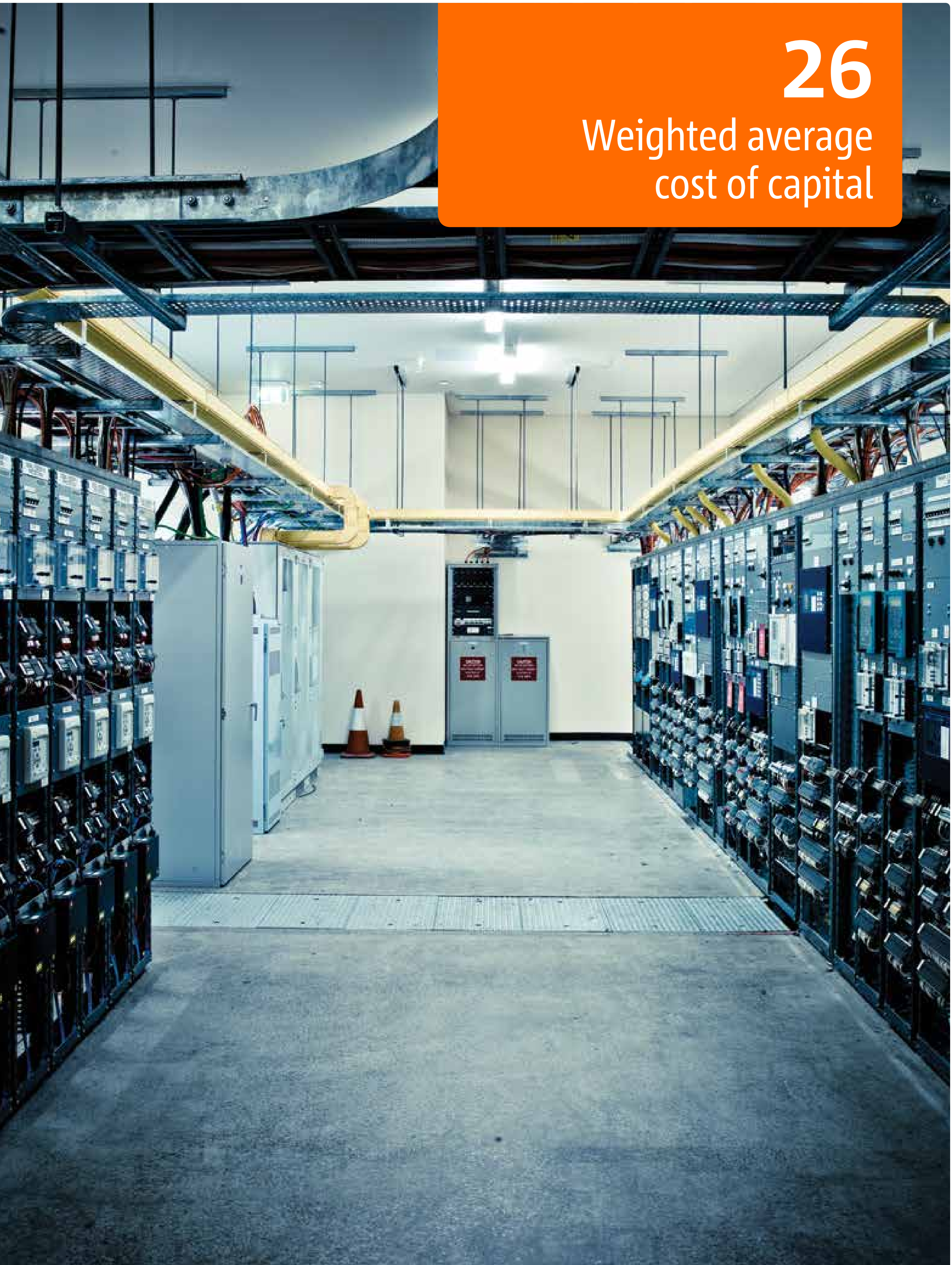
	2015/16	2016/17	2017/18	2018/19	2019/20
Opening RAB	3,829.4	4,178.3	4,561.4	4,934.1	5,302.4
Plus capital expenditure, net of contributions and disposals	481.2	544.4	561.3	583.8	559.0
Less straight line depreciation	(229.9)	(267.8)	(304.9)	(341.3)	(373.5)
Plus nominal actual inflation on opening RAB	97.6	106.5	116.3	125.8	135.2
Closing RAB	4,178.3	4,561.4	4,934.1	5,302.4	5,623.1

Table 25.4: Alternative Control Services RAB roll forward to 2020 ($ million, nominal)

	2015/16	2016/17	2017/18	2018/19	2019/20
Opening RAB	85.4	89.8	93.3	97.9	100.5
Plus capital expenditure, net of contributions and disposals	10.6	10.5	12.5	12.0	8.4
Less straight line depreciation	(8.3)	(9.3)	(10.3)	(12.0)	(13.1)
Plus nominal actual inflation on opening RAB	2.2	2.3	2.4	2.5	2.6
Closing RAB	89.8	93.3	97.9	100.5	98.4

Note: These calculations are extracted from the completed version of the AER's Post Tax Revenue Model.

26 Weighted average cost of capital



26

Establishing a fair and efficient allowed rate of return is amongst the most important aspects of the regulatory determination. If the rate of return is set too high, prices are higher than they need to be. On the other hand, if the rate of return is too low, we cannot attract the investment necessary for us to remain financially resilient and continue to deliver the quality of service customers expect.

Since SA Power Networks' 2010 Determination, there have been two fundamental changes to the way in which the regulatory framework establishes the allowed return on capital.

Firstly, the new system requires the AER to consider a much broader range of inputs when setting the allowed rate of return on capital. If the new system is implemented well, looking at a wider range of models and evidence should enable a better informed judgement to be made about where the balance lies between over-and under-pricing of investment capital. Implemented in this way, we calculate the return on equity to be [10.45]%[135] which is similar to, albeit lower than, the returns that were set in the 2010 Determination.

On the other hand, if the new system is implemented in a way in which the AER selects one model or other input to have a dominant influence in setting the allowed rate of return, the new system will not deliver any significant improvement to the way in which allowances are set. Last year the AER published the Rate of Return Guideline that explains how the AER intends to undertake its decision under the new rules and, indeed, the AER intends to use the Sharpe-Lintner Capital Asset pricing model (**SL-CAPM**) as the "foundation model" which means giving it a preeminent role in determining the allowed rate of return on equity.

At the same time, the AER has indicated that it intends to down-grade the 'equity beta' to its lowest level ever in Australian regulatory decision making. The 'equity beta' is the key input into the SL-CAPM that represents the AER's view on how risky it is to operate an energy network business compared with other businesses.

The combined effect of giving the SL-CAPM preeminent weight in a historically low risk free rate environment and the downgrading of the equity beta is to significantly reduce our allowed rate of return on equity compared with past allowed rates of return.

Meanwhile, we are confronted with new and significantly increased risks that throw into question whether investors should be willing to invest in electricity network businesses. As explained below, new "disruptive technologies" raise fundamental questions about what the network will look like in the future and whether it will be possible to obtain an adequate return on investments. Now is not the time to be reducing risk adjusted returns because there is a real risk that if the return on equity is substantially reduced, insufficient investment incentives will exist affecting the level of financial resilience and service that customers expect from their electricity distributor.

135 Using data from a representative 20 business days ending on [29 August 2014]. The figures displayed in square brackets (ie [ ]), will be updated as close to the regulatory determination date as practical.

Secondly, the method for establishing the return on debt, will progressively transition towards a system by which each year our allowed rate of return on debt will automatically reflect the gradual evolution of rates on 10-year corporate bonds. In some ways, the previous system was somewhat of a lottery in which network businesses were incentivised to hedge all of their debt against the rates applying "on the day" of their five yearly revenue determination and this rate had a material effect on customer prices. Every year, the new trailing average system updates one tenth of the weighting given to the average rate so the average should remove the element of chance, keep up to date and smooth any effects that rate movements have on pricing. On this topic, we have relatively minor differences of view compared with the AER's proposals as set out in the Rate of Return Guideline. We have also obtained advice on the value of the 'new issue premium' which measures the difference between the price at which an energy business can roll-over its debt portfolio and prices that are used by the AER from secondary markets where debt is re-sold. Currently, we calculate the average return on debt in the first year as reported by the two services to be [5.44]% which, together with a new issue premium of [0.30%] would give a total allowed rate of return on debt of [5.74%].[136]

The final element of the WACC parameter package is the valuation ascribed to imputation credits (also known in finance and regulatory circles as "gamma"). The Rate of Return Guideline proposes a new 'conceptual framework' for gamma which we consider to be ill conceived. SA Power Networks does not consider that there is any reason for a change to the 0.25 estimate that applied previously and consequently that is the estimate used in this Proposal.

26.1

Context within which the revenue determination will be made

Until now, the AER has set our equity returns using solely the SL-CAPM. When implementing the SL-CAPM:

- the AER has estimated the risk-free rate as the yield on government bonds drawn from a short period shortly before the final decision; and
- the AER has relied primarily on the 'Ibbotson approach' to estimate the market risk premium (**MRP**). This approach uses more than 100 years of historical data to establish a very long term estimate of the market risk premium that reflects the average market conditions over the long historical period that is used.

That is, one of the SL-CAPM parameters (risk-free rate) reflects the contemporaneous market conditions at the time of the decision, whereas another, MRP, reflects the average market conditions over a long historical period. Unless the contemporaneous market conditions are similar to the long-run average market conditions, there is an inherent internal inconsistency in using parameters estimated in this way.

136 Using the same representative 20 business day period.

There is no evidence in the real world to suggest that required returns on risky investments move in 'lock-step' with yields on government bonds. Indeed there is considerable evidence to suggest that there is an inverse relationship between the return on risk free assets and the market risk premium. For example, during periods of financial crisis government bond yields decline (as investors' quest for safe haven assets bids up the price of government bonds) and risk premiums are obviously at elevated levels.

Additionally, the equity beta has progressively been down-graded from 1.0 for most of the NEM[137] to 0.8 and now proposed to be 0.7 in the face of firm evidence that electricity network businesses are becoming more risky over time compared with a balanced market portfolio.

By contrast, as discussed in detail in Section 26.3 of this chapter, there is a wealth of evidence to conclude that electricity network businesses are experiencing significant increases in risk. Debates can be had as to whether these risks are best included in the beta or elsewhere but under the current model these increases are accommodated neither in the equity beta nor in any other part of the regulatory framework.

Unless a change of approach is adopted, these two factors (ie, the mismatch of a contemporaneous risk free rate with a very long term average market risk premium and the progressive downgrading of the equity beta) will result in:

- a significant downward trend in regulated returns over the period that the AER has regulated the South Australian electricity distribution sector and even over the last few months with no concrete justification for such a reduction; and
- very low regulated returns compared with any historic measures.

For example, for SA Power Networks the figures when the last two regulatory determinations were made and over the last 12 months are as follows:

Table 26.1: Historical risk free rates and MRP assumptions.

Date	'On the day' risk free rate	Beta assumption in use or in Guideline at the time	MRP assumption in use or in Guideline at the time	Returns applying current assumptions
Mar 2005	5.65%	0.9	6%	11.05%
May 2010	5.48%	0.8	6.5%	10.68%
Oct 2013	3.97%	0.7	6.5%	8.52%
Sept 2014	3.41%	0.7	6.5%	7.96%

Note: 10-year government bond yield at the end of each month (end of Aug 2014) has been used for the risk-free rate.

In our view this is a powerful basis to conclude that substantial changes in the approach are needed. The AEMC's rule change, which requires the AER to review a broader range of evidence and exercise discretion, has enabled the change to occur but at least equally important is what evidence the AER uses in setting the return on equity and how that discretion is used to combine the range of relevant evidence.

137 Note that in South Australia the figure was 0.9.

26.2

Relevant requirements of the National Electricity Rules and the National Electricity Law

The National Electricity Rules (**NER**) provide that the allowed rate of return for each of debt and equity must be commensurate with the efficient financing costs of a benchmark entity with a similar risk profile as that which applies to SA Power Networks in respect of its provision of standard control services.[138] The NER also requires the value of imputation credits to be identified (**the Gamma**).[139]

Previously the NER contained very specific requirements on how the above principle should be implemented in that:

- the return on equity had to be established using solely the SL-CAPM model, with an adjustment factor for the value of imputation tax credits; and
- the return on debt had to be established using an 'on the day' method by which a single figure was set for the duration of the five year revenue control period even if rates moved significantly during the period.

In 2011, the AER and the Major Energy Users each proposed Rule changes concerning the way in which the allowed rate of return is set which resulted in a detailed reconsideration of the NER and the National Gas Rules (**NGR**) by the Australian Energy Markets Commission (**AEMC**) and substantial revisions to the Rules in 2012.

The new Rules now require that when the AER sets the allowed rate of returns, regard must be had to all relevant estimation methods, financial models, market data and other evidence for both the return on equity and the return on debt,[140] not just the SL-CAPM and 'on the day' method for establishing the return on debt.

The AER is also required by the National Electricity Law (**NEL**), when making its determination, to:

- do so in a manner that is likely to contribute to the achievement of the national electricity objective (**NEO**), including the promotion of efficient investments in network infrastructure;[141] and
- to take into account the principle that a regulated network service provider should be provided with a reasonable opportunity to recover at least its efficient costs.[142]

As part of the new NER, the AER is also required[143] to make (and periodically update) Rate of Return Guidelines that set out the methodologies that the AER proposes to use in estimating the allowed rate of return.

138 NER 6.5.2(b).
139 NER 6.5.3.
140 NER 6.5.2(e).
141 NEL sections 7 and 16(1).
142 NEL sections 7A and 16(2)(a).
143 NER 6.5.2(m).

The AER undertook a detailed consultation process and published the first such Rate of Return Guideline in 2013 (**Guideline**). The main elements of the Guideline are:

- a proposal to retain the Sharpe-Lintner capital asset pricing model as the single model that is used to estimate the required return on equity. The Guideline refers to the SL-CAPM as the 'foundation model' and notes that two other models — the Dividend Discount Model (**DDM**) and the Black-CAPM — will each be used only to inform the estimates of individual parameters within the SL-CAPM. The Guideline also states that the Fama French model will not be used in any way;
- a proposal to adopt a new conceptual framework for establishing the value of imputation credits; and
- a proposal to transition over a 10-year period from the 'on the day' method of establishing the debt allowance to a 'trailing average' method.

SA Power Networks' Proposal is not required to follow the approach set out in the Guideline nor is the AER required to follow the approach in the Guideline in its decision. This is an important difference since the previous Rules which had required 'persuasive evidence' for any departures from the Statement of Regulatory Intent. It is, however, necessary for us to identify in this Proposal any departure from the Guideline.[144] We must also provide the formula that will determine the return on debt each year of the RCP and the value for income tax credits.[145]

SA Power Networks has departed from the Guideline in the following respects:

Equity: SA Power Networks endorses the use of multiple models for establishing the return on equity but we depart from the Guideline in that we do not use the SL-CAPM as the foundation model. Instead we establish the return on equity (and each of the parameters that make up the cost of equity) using a weighted average of the four leading return on equity models (SL-CAPM, Black-CAPM, the DDM and the Fama French Model). The weightings are based on expert advice that avoids 'double weighting' where different models share common theoretical elements (ie, SL-CAPM and Black-CAPM) and which take account of the particular limitations of the models.

Valuation of income tax credits: SA Power Networks does not adopt the Guideline's 'conceptual framework'[146] because, in our view, it is incorrect and inconsistent with the NER. Instead, in the determination of theta, we maintain the conceptual approach that was accepted by the Australian Competition Tribunal (**Tribunal**) when it considered an appeal on our last revenue determination, which is now further supported by a range of updated and wholly new market valuation studies.

Debt: SA Power Networks adopts the trailing average and transition path set out in the Guideline with the following minor variations:

- we propose a benchmark credit rating of BBB; and
- we propose the additional new issue premium.

This chapter discusses each of these elements in turn, including our reasons for the departures.

26.3

Allowed rate of return on equity

In order to implement the new Rule requirements it is necessary to:

- consider the degree of risk faced by the benchmark efficient network service provider;
- identify all relevant estimation methods, financial models, market data and other evidence;
- establish estimates for each parameter required for the relevant models;
- calculate rates of return on equity using the relevant estimation methods, financial models, market data and other evidence; and
- distil all the relevant inputs into a single figure for the allowed rate of return on equity.

This section commences with a discussion of the degree of risk faced by a benchmark efficient network service provider. For the reasons set out below, we consider that the issue was not adequately addressed in the Guideline process. This is relevant both when considering individual parameters (such as the beta used in the capital asset pricing models) and at an aggregate level delivers outcomes that are as stark as they are counter-intuitive. Although risk is clearly rising significantly, the direction of regulatory decision making as articulated in the Guideline is to further reduce the regulated returns on equity after a succession of previous reductions.

We then proceed to set out our concerns in relation to the approach that the Guideline proposes for establishing the allowed rate of return for equity.

While we agree with the position in the Guideline as to the range of relevant estimation methods, financial models, market data and other evidence, based on expert input from SFG Consulting, and for the reasons discussed, our proposed allowed rate of return departs from the Guideline in how we use that relevant information. In particular:

- we do not use subsets of the relevant evidence to establish "primary ranges" for the SL-CAPM parameters;
- we employ each of the Fama French Model, Black-CAPM, DDM and SL-CAPM to produce a point estimate for the return on equity;
- we establish the parameters necessary to estimate each of the four models; and
- we establish the applicable return on equity as a weighted average of the above models using weightings recommended to us by SFG Consulting.

144 Schedule 6.1.3(9).
145 Schedule 6.1.3 (9A) and (9B).
146 AER, Rate of Return Guideline, December 2013, p. 24.

26.3.1 Risk profile of the benchmark electricity distribution network service provider

Risk is an important consideration in setting the allowed rate of return for equity. Electricity network operators compete with other businesses to attract investment capital and investors will only provide the investment capital we need for the business if a competitive return is provided that adequately rewards the investors for the risks of the investment. For customers, it is important that regulatory decisions do not over-reward businesses for risk (because prices would be higher than they need to be) and equally that these decisions do not under-reward businesses for risk (because under-capitalised businesses cannot make required investments or meet required service standards and they carry excessive risk of financial failure).

In considering the risk of electricity network investments made during the RCP it is important to remember that the timeframes are long term timeframes. The assets in any electricity network generally last at least 50 years.

Since the beginning of the National Electricity Market (**NEM**), the AER and its predecessors have regarded electricity network businesses as being lower risk than the market average and, indeed, the returns we have been permitted to earn for investment risks have been declining over time.

Until recently, treating our business as lower than average risk would seem to have been appropriate. For at least a century, the principal characteristics of the electricity system have not changed: the most cost effective way to manage load reliably has been to connect almost everyone to the interconnected network that provides access to centralised thermal generation. Throughout the 20 years that the economic regulation has applied through the NEM, demand has been consistently growing in a way that is less volatile than many other industries and technological change has been slow. In some ways the regulatory framework has assisted in reducing risk.[147]

However, the risk of electricity network businesses has changed dramatically in the very recent past in ways that were not considered as recently as the 2013 report commissioned by the AER from Frontier Economics[148] as part of the Guideline process. There are three main interrelated causes for this.

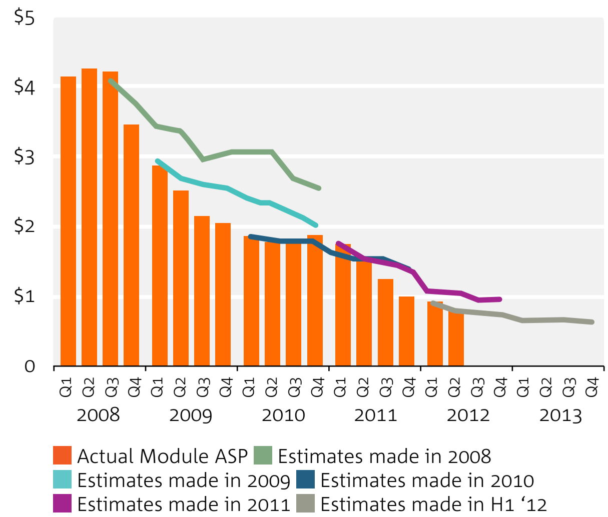
Essentially our business is confronted with two possible future scenarios, one in which we evolve and survive and the other in which our network progressively becomes redundant.

In this section of the submission we explain how the risks we face have substantially changed.

First, we consider solar panels as the main example of dramatic developments in distributed generation.[149] Solar panels have been available since the 1970s but they played almost no part at all in supplying electricity to the grid-connected mass market in the ensuing 30 years because the technologies used to manufacture them were price prohibitive. In recent times, prices of solar cells have been falling rapidly. This change largely occurred because of governmental policies in Germany and Italy[150] to encourage the installation of solar panels. With vastly increased sales volumes, manufacturers in Europe and China invested heavily in technology to reduce solar panel costs and invested in much larger scale, low cost manufacturing facilities. Since 2008, prices of the panels themselves have dropped 80% and the US Department of Energy has observed that prices for modules (ie, the panels together with their housings etc.) have been dropping rapidly and consistently experts have under-estimated the price falls.

*"As shown in Figure 26.1, most analysts in recent history have underestimated the rapid reductions in module prices. This figure illustrates that analysts have continually lowered their estimated global module average selling price (**ASP**) for future years each year since 2008, but most projections were still higher than actual prices. In the first half of 2012, analysts estimated that global module ASP would decline to approximately $0.82/W in 2012 and $0.74/W in 2013. Some companies are currently selling modules below this level, indicating that even further price reductions beyond these recent analyst projects are plausible. Though not shown here, analysts project inverter and BOS costs to decline over this period as well, placing further pressure on total system prices." (U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, 2012).*

Figure 26.1: Actual module average selling price reduction vs average analyst expectations



147 For example, in order to facilitate investments required to achieve high reliability expectations, the Rules expressly provide that there are not asset write-offs or write-downs (also known as "optimisation").

148 Frontier Economics, 'Assessing risk when determining the appropriate rate of return for regulated energy networks in Australia', A report prepared for the AER, July 2013.

149 As noted on page 7 of Accenture's 'Forging a Path towards a Digital Grid, Global perspectives on smart grid opportunities' 2013, smaller-scale wind is another distributed technology to which this discussion applies.

150 Today those two countries account for approximately 50% of the world's 100GW installed capacity.

The effect of dramatically lower global solar installation prices is that global businesses are aggressively marketing solar systems in Australia.[151] The Australian Energy Market Operator (**AEMO**)[152] has reported significantly increased penetration in South Australia and AEMO projections are that this should continue into the near future.

"Rooftop PV systems generated a total of 497 GWh in 2012–13, approximately 3.7% of South Australia's annual energy. Under the moderate uptake scenario, annual energy generated by rooftop PV is expected to reach 1,119 GWh by 2022–23, equivalent to 8.9% of South Australia's annual energy. This is an average annual growth of approximately 7.5% over the 10-year period."

The second significant development concerns so called 'smart' technology that enables better management and control by the consumer of when and how they consume electricity. To date this has been conceived of as being a technology to improve the performance of the traditional grid connected power industry but many of the same technologies will be able to be used with or without grid connection.

For the first time, since before the advent of economic regulation, AEMO[153] has reported lower demand:

"In 2012–13, South Australia's residential and commercial sector annual energy was 11,115 GWh, or 83% of total annual energy. This was 0.7% (80 GWh) lower than in 2011–12 (11,195 GWh).

Figure x shows that over the 2008–09 to 2012–13 period, residential and commercial annual energy decreased by 553 GWh, an average annual rate of -1.2%. This decline was driven by:
- *average annual residential electricity price increases of 10.1% over the 2008–09 to 2012–13 period. This was due to increased network costs and to a lesser extent the introduction of "green energy policies" (such as renewable energy targets and a price on carbon emissions); and*
- *increased rooftop PV output from negligible levels in 2008–09 to 497 GWh in 2012–13."*

The third significant factor to consider concerns power storage, most notably batteries and super capacitors. The state of technology in the power storage industry is likened to that of the solar panel industry in 2008, before the substantial price falls:

"Developments like the Tesla "Gigafactory" will be a game changer and will help bring costs down. He says battery storage is at a similar stage to solar five years ago, just before its massive cost fall."[154]

As for solar panels, the price reductions are resulting from a race between global manufacturers to improve production technology and scale economies in manufacturing to win large scale new business opportunities in industrialised countries.

For example, European Union air quality directives have contributed to each of the City of Paris and the City of London letting contracts for shared car schemes each of which will have 3,000 electric cars[155] to replace 22,000 privately owned petrol vehicles in their cities. The French based global power storage conglomerate (Bollore) bid aggressively to win each of these contracts primarily in order to 'prove up' the economics of deploying its lithium metal polymer (**LMP**) battery on a large scale. Bollore's LMP is just one of several competing storage technologies that are attracting substantial investments.

Australia is a member of the OECD's sister organisation the International Energy Agency which published an authoritative report this year[156] recognising that energy storage is beginning to play a part in mainstream electricity supply. A key conclusion of the report is that:

*"Energy storage technologies are valuable in most energy systems, with or without high levels of variable renewable generation. Today, some smaller-scale systems are cost competitive or nearly competitive in remote community **and off-grid applications.**"*

*"Public investment in energy storage research and development has led to **significant cost reductions**. However, additional efforts (eg, targeted research and development investments and demonstration projects) are needed to **further decrease energy storage costs and accelerate development.**"*

The report lists the following current energy storage projects:
- NaS batteries (Presidio, Texas, United States and Rokkasho Futamata Project, Japan);
- Vanadium redox flow (Sumimtomo's Densetsu Office, Japan);
- Lead-acid (Notrees Wind Storage Demonstration Project, United States);
- Li-ion (AES Laurel Mountain, United States); and
- Lithium Polymer (Autolib, France).

Taken separately, each of the above developments (reduced costs for distributed generation, reduced costs for energy storage and the improved ability for consumers to manage their consumption) pose their own types of new risk for power network operators. Taking each in isolation it is possible to envisage that investors in energy networks might be immunised from risk as the Guideline suggests because inherent in the way these regulations work is that the significant majority of customers have a clear incentive to stay connected to the grid.

However, when these three factors combine it calls into question whether customer disconnections from the grid might be significant enough to put at risk the viability of the whole regulated price recovery system.

151 Mr T. Werner, CEO of global solar power conglomerate, SunPower recently stated that 'The economics of solar work better in Australia than in America', per 'SunPower says Australia could be global leader in local generation' REneweconomy, 29 April 2014.
152 South Australian Electricity Report 2013.
153 South Australian Electricity Report 2013.
154 Mr T. Werner, CEO of SunPower, per 'SunPower says Australia could be global leader in local generation' REneweconomy, 29 April 2014.
155 There are already 2,000 such cars deployed under this contract in Paris (https://www.autolib.eu/faq/general-questions/the-autolib-service/).
156 Technology Roadmap, Energy Storage.

Customers connect to the grid and stay connected for two main reasons — to gain access to cost competitive generation and to have access to a reliable supply of electricity as and when they need electricity.

The risk that now looms within the relevant 50 year investment horizon is that a significant number of customers may disconnect from the grid and instead install solar panels or other distributed generation combined with battery storage — either on an individual basis or in clusters linked to new micro-grids. The NEM's Consumer Advocacy Panel funded the preparation of a report "What Happens When We Un-Plug" that studied whether it might be cost effective for consumers in Bendigo, Werribee and Melbourne to disconnect individually or in clusters. It found that it was already economic for some customers to disconnect and for most others it will become economic to do so before 2020. The report notes that:

"In other areas of Australia, and in particular the NEM jurisdictions of New South Wales, Queensland and South Australia, milder climate zones, better solar radiation and higher-than-average electricity prices would make standalone power solutions more viable and sooner."

Horizon Energy, whose geographic footprint is immediately to the west of our network, is already tendering for solar and storage solutions:

"Horizon Energy … in March tendered for operators to supply large battery storage and solar systems for some towns as it contemplated whether centralised generation had any future in these regional areas."[157]

Other businesses are already positioning to provide off-grid solutions by-passing network operators altogether:[158]

"SunPower itself is looking at deploying systems that combine solar PV and storage and will soon announce its first pilot schemes in Australia, likely to be rolled out through its partly owned local retailer Diamond Energy. It is also looking at microgrid solutions in Australia, although it sees the biggest potential in the commercial roof top market."

"'We do not know how it will evolve. It will be messy, that's what we do know,' Werner says. 'But it is great to be in our position because we are a disruptor.'"

Investment analysts are already downgrading electricity utility bonds in other countries on this basis:[159]

"Electric utilities … are seen by many investors as a sturdy and defensive subset of the investment grade universe. Over the next few years, however, we believe that a confluence of declining cost trends in distributed solar photovoltaic (PV) power generation and residential-scale power storage is likely to disrupt the status quo. Based on our analysis, the cost of solar + storage for residential consumers of electricity is already competitive with the price of utility grid power in Hawaii. Of the other major markets, California could follow in 2017, New York and Arizona in 2018, and many other states soon after.

In the 100+ year history of the electric utility industry, there has never before been a truly cost-competitive substitute available for grid power. We believe that solar + storage could reconfigure the organization and regulation of the electric power business over the coming decade. We see near-term risks to credit from regulators and utilities falling behind the solar+ storage adoption curve and long-term risks from a comprehensive re-imagining of the role utilities play in providing electric power."

It is apparent from the discussion above how difficult it can be to forecast the numbers and speed of disconnections because they are influenced by unpredictable technological changes prompted in large part by government environmental policies in other countries as well as local geography and local governmental policies.

The Guideline also suggests that our business is low risk because our assets are not subject to being 'optimised' (ie, written off if they are not fully used). In a similar way, we can adopt accelerated regulatory depreciation to bring forward the recovery in the case of obsolescence.

Additionally, through the mechanism of tariff classes, to some extent we are able to differentiate in pricing to provide incentives for marginal customers to stay connected but that mechanism only operates effectively if an even narrower range of customers can carry all the redistributed costs of the unused infrastructure which certainly cannot be assured.

Each of the above mechanisms assumes that we continue to have a large connected customer base that can absorb these costs. Electricity industry commentators often refer to a 'tipping point' or 'point of inflection' where the regulated pricing system becomes unsustainable and an endless spiral of disconnections commences. If a significant number of customers find distributed generation and storage more cost effective than staying connected, the prices for those who remain connected would rise to recover the costs of the infrastructure no longer used for the customers who had disconnected. As the prices are raised, it creates the incentive for another group of customers to disconnect and so on until there is not a sufficient customer base to be able to cover the costs of the whole system.

157 'Australian network operators ready to ditch poles and wires', Reneweconomy.com.au, 2014.
158 'SunPower says Australia could be global leader in local generation', RenewEconomy, 2014.
159 Barclays credit strategy team per Barron's Income Investing, 2014.

With the threat of competition from off-grid electricity installations, a number of prominent energy investment analysts have been advocating entrepreneurial investments by network operators and energy retailers to improve the range and quality of services supplied to grid connected customers.[160]

"At PwC we contend that the utility of today is outdated and is struggling to meet the needs of its customers while maintaining acceptable returns to shareholders. The so-called 'death spiral' is a prime example. Traditional large scale power utilities are losing relevance as customers take greater control of their own energy supply needs. To survive and prosper the 'utility of the future' will have to provide much more than reliable energy supply — it must respond to a diverse range of customer, business and community demands and do so in a rapidly changing regulatory and technological environment."

Such services could include providing equipment and services that enable the programmed or remote management of devices that consume electricity. However, the collective ability of retailers and network operators to work together to meet the competition from off-grid solutions is hampered by the architecture of the NEM which provides for the separation of the different businesses involved in an interconnected system.

The Guideline concluded electricity and gas networks were low risk based on a report by Frontier Economics[161] but, as discussed in paragraph 105 of SFG Consulting's Beta report, the Frontier Economics document does not provide support for an equity beta of below 1 and, indeed Frontier Economics does not state that the beta should be below that figure. Additionally, since the Frontier Economics report was published, many of the authoritative reports referred to in this submission by authors such as the International Energy Agency and AEMO have taken the analysis further by examining data that was not made available to Frontier Economics. Frontier Economics was not asked to perform calculations of the economics of disconnection from the grid of the sort prepared by the Consumer Advocacy Panel funded project nor did it consider the effect that regulations might have in accelerated disconnection from the grid or what risks large scale disconnection might have.

It is incumbent upon the AER to engage with the above material and identify how these risks are accommodated in the over-all allowed return on capital. In SA Power Networks' view the above material certainly demonstrates that there is no basis to continue the trend of reducing regulated returns on the assumption that energy network businesses are low risk.

26.3.2 Relevant financial models

As noted by the AEMC, there is no single model that is free of weaknesses and no single model captures all the strengths of the others. Therefore resort must be had to a range of relevant models.

We agree with the conclusions of the Guideline that the relevant financial models are:

- the SL-CAPM;
- the Black-CAPM;
- the Fama French Model[162]; and
- the DDM.

Since the publication of the Guideline, SFG Consulting has prepared a suite of reports in May this year which explore in detail a series of issues raised in the Explanatory Statement that accompanied the Guideline. The first report addresses the issues raised in connection with the equity beta in the context of the SL-CAPM. The next three reports focus on the issues raised in relation to each of the other financial models and a fifth report addresses how to set a single allowed rate of return figure for equity using the above inputs.

160 PWC, 'Utility of the future — A customer-led shift in the electricity sector', An Australian context, April 2014, p. 2.

161 Frontier Economics, 'Assessing risk when determining the appropriate rate of return for regulated energy networks in Australia', A report prepared for the AER, July 2013.

162 Although the AER found the Fama French Model to be relevant, its Guideline proposes to give it no weight.

Table 26.2: SFG Consulting Report References

The references for these SFG Consulting reports are as follows:
SFG Consulting, 'Equity beta', 12 May 2014
SFG Consulting, 'Cost of equity in the Black Capital Asset Pricing Model', 22 May 2014
SFG Consulting, 'The Fama-French model', 13 May 2014
SFG Consulting, 'Alternative versions of the dividend discount model and the implied cost of equity', 15 May 2014
SFG Consulting, 'The required return on equity for regulated gas and electricity network businesses', 6 June 2014
Additionally, SA Power Networks commissioned an update of the fifth report from SFG Consulting using financial market data at the time this Proposal was written:
SFG Consulting, 'Updated estimate of the required return on equity', 24 August 2014
SFG Consulting's reports build on material the Energy Networks Association put forward as part of the Guideline process:
NERA Economic Consulting, *'Review of cost of equity models'*, June 2013
NERA Economic Consulting, 'Estimates of the [Black CAPM] zero beta premium', June 2013
SFG Consulting, 'Dividend discount model estimates of the cost of equity', June 2013
SFG Consulting, 'Evidence on the required return on equity from independent expert reports', June 2013
CEG Consulting, 'Estimating the return on the market', June 2013
CEG Consulting, 'Estimating E[Rm] [expected return on the market] in the context of regulatory debate', June 2013
SFG Consulting, 'Regression-based estimates of risk parameters for the benchmark firm', June 2013
SFG Consulting, 'The Vasicek adjustment to beta estimates in the Capital Asset Pricing Model', June 2013
CEG Consulting, 'Information on equity beta from US companies', June 2013
SFG Consulting and Monash University, 'Comparison of OLS and LAD regression techniques for estimating beta', June 2013
SFG Consulting and Monash University, 'Assessing the reliability of regression-based estimates of risk', June 2013
Incenta Economic Consulting, 'Term of the risk free rate for the cost of equity', June 2013
NERA Economic Consulting, *'The market, size and value premiums'*, June 2013
NERA Economic Consulting, *'The Fama-French three-factor model'*, October 2013
SFG Consulting, 'Reconciliation of dividend discount model estimates with those compiled by the AER', October 2013
CEG Consulting, 'AER equity beta issues paper: International comparators', October 2013
SFG Consulting, Letter: '*Water utility beta estimation*', October 2013

The first step in setting the return on equity is to identify the range of available financial models and consider their characteristics. SFG Consulting states[163]:

"In our view, these four models all provide evidence that is relevant to the estimation of the required return on equity for the benchmark efficient entity. We reach this conclusion for the following reasons:

a) All four models have a sound theoretical basis. *The Sharpe-Lintner CAPM, Black CAPM and Fama-French model are all based on the notion that the expected return on any asset is equal to a linear combination of the returns on an efficient portfolio and its zero covariance portfolio. This basic theoretical framework is the same for all three models, which differ only according to the way the efficient portfolio and the zero-covariance portfolio are determined. For example, under the Fama-French model the efficient portfolio is formed by combining three factor portfolios, whereas under the Sharpe-Lintner CAPM and Black CAPM the market portfolio (proxied by a stock market index) is assumed to be efficient. The Sharpe-Lintner CAPM further assumes that investors can borrow and lend as much as they like at the risk-free rate. The dividend discount model is based on the notion that the current stock price is equal to the present value of expected future cash flows (dividends).*

b) All four models have the purpose of estimating the required return on equity as part of the estimation of the cost of capital. *This point is not weakened by the fact that the models can be used to inform other decisions as well. For example, the Sharpe-Lintner CAPM and the Fama-French model can also be used to compute "alpha" for the purpose of mutual fund performance evaluation.*

c) All four models can be implemented in practice. *For all four models, there is a long history and rich literature concerning the estimation of model parameters. This literature has developed empirical techniques, constructed relevant data sets, and considered issues such as the trade-off between comparability and statistical reliability.*

d) All four models are commonly used in practice. *Some form of CAPM is commonly used in corporate practice and by independent expert valuation practitioners. The Black CAPM is commonly used in rate of return regulation cases in other jurisdictions (where it is known as the "empirical CAPM"). The dividend discount model is also commonly used in rate of return regulation cases in other jurisdictions (where it is known as the "discounted cash flow" approach). The Fama-French model has become the standard method for estimating the required return on equity in peer-reviewed academic papers and its use to estimate the required return on equity is required knowledge in professional accreditation programs."*

163 'The required return on equity for regulated gas and electricity network business', 6 June 2014.

Key comments in relation to each model are as follows:

Table 26.3: Comments in relation to financial models

Model	Comments
SL-CAPM	The SL-CAPM is the model with which Australian economic regulators are most familiar because it has been required since the beginning of the NEM. It is also commonly used in most other infrastructure revenue regulatory frameworks. However, empirical studies have consistently found the performance of this model to be poor. As SFG Consulting explains: *"In particular, stocks with low beta estimates earn higher returns than predicted by the Sharpe-Lintner CAPM, and stocks with high beta estimates earn lower returns than predicted by the Sharpe-Lintner CAPM. This empirical result has been documented in literature over 50 years ... . The poor empirical performance of the Sharpe-Lintner CAPM likely occurs for two reasons. First, risks other than systematic risk are incorporated into share prices (in particular, stocks with a high book-to-market ratio persistently earn higher returns than stocks with a low book-to-market ratio). Second, the common measurement of systematic risk — the regression coefficient of excess stock returns on market returns — is an imprecise measure of risk."*[1] A further problem arises when this model is implemented by using a current government bond yield to estimate the risk free rate in combination with a very long run average of historical excess returns to estimate the MRP. There are reasons why the risk free rate is likely to move in the opposite direction to the MRP. When there is a significant economic downturn or a financial crisis, investors tend to seek increased compensation for risk. Those same investors tend to shift their funds into safe and liquid investments such as government bonds, raising their price and lowering yields. At the same time, the central bank also tends to lower the cost of borrowing, putting further downward pressure on government bond yields. These are precisely the effects that were observed at the onset of the global financial crisis. The movements in government bond yields and equity risk premiums should tend to off-set each other which should reduce volatility in the overall required return on equity (although, of course, one variable will usually move more than the other, meaning that required returns on equity will not be perfectly stable). If the current risk free rate is below its long term average (as it is currently) then adding a constant long run average MRP will tend to understate the required rate of return on equity. It would not meet the regulatory requirements to under-estimate the required returns during a down-turn even if there were an over-estimate during up-turns in the business cycle. In its Final Determination, the AEMC articulated the need to ensure that the allowed return be set in each regulatory determination in such a way that it is commensurate with the prevailing conditions in the market for equity funds at the time of the determination. The AEMC stated that: *"If the allowed rate of return is not determined with regard to the prevailing market conditions, it will either be above or below the return that is required by capital market investors at the time of the determination. The Commission was of the view that neither of these outcomes is efficient nor in the long term interest of energy consumers. [p. 44]"* and: *"The second principal requirement is that the return on equity must take into account the prevailing conditions in the market for equity funds. It reflects the importance of estimating a return on equity that is sufficient to allow efficient investment in, and efficient use of, the relevant services. However, this requirement does not mean that the regulator is restricted from considering historical data in generating its estimate of the required return on equity. Rather, it ensures that current market conditions are fully reflected in such estimates to ensure that allowed rates are sufficient for efficient investment and use. [p. 69]"* A significant problem with setting the allowed return in a manner that is inconsistent with the prevailing conditions at any point in time (even if in the long run over-estimates are balanced with under-estimates) distorts incentives for efficient investment in the use of the regulated service in both the high and low parts of the business cycle to the long term detriment of consumers of electricity. For example, setting an allowed return that is lower than the prevailing conditions creates an incentive for regulated businesses to postpone efficient investment and for customers to over-use the regulated service. The converse applies if the allowed return is higher than the prevailing conditions. The decision needs to produce the best estimate of the required return at every determination and should not be based on estimates known to be downwardly skewed at this point in the business cycle.

1 'Cost of Equity in the Black Capital Asset Pricing Model', 22 May 2014, p. 2; see also SFG Consulting: 'Equity Beta', 12 May 2014, pp. 6–7.

Model	Comments
Black-CAPM	The Black CAPM is a 'next generation' model in that it builds on the SL-CAPM by incorporating additional flexibility. It is related to the SL-CAPM in the following way: *"[T]he Sharpe-Lintner CAPM remains a specific application of the more general model, the Black CAPM."* [2] *"The Black CAPM does not rely upon the assumption that all investors can borrow at the risk-free rate of interest."*[3] The Black CAPM has been shown to provide a significantly better empirical fit to the data, and it is used extensively in US regulation cases where it is referred to as the "empirical CAPM". Further, even if the Black CAPM does not perfectly model the relationships in question SFG Consulting point out that: *"because the Black CAPM is more general in that it allows flexibility in a parameter input (r_z versus r_f) it gives some chance of aligning with historical stock returns."*[4] Empirical studies have found the performance of this model to be better than the SL-CAPM but it is known to have a downward bias for value stocks: *"[S]tocks with above-average book-to-market ratios would be expected to have returns above that predicted by the Black CAPM and a zero beta premium of 3.34%. If the risks associated with high book-to-market stocks are not incorporated elsewhere, and the Black CAPM alone is used to estimate the cost of equity with a zero beta premium of 3.34%, the cost of equity will be understated."*[5] The same implementation problem arises as with the SL-CAPM when the current returns on central bank debt is used as the estimate of the risk free rate and this is added to a long run average estimate of MRP.
Fama-French Model	This model provides separately for an additional return on value stocks and empirical studies in the US and Australia have confirmed that: *"The Fama-French model has the advantage of providing an unambiguously better fit to the data than the Sharpe-Lintner CAPM."*[6] If it is excluded from the analysis, downwardly biased allowed rates of return would be set because regulated businesses are value stocks. As SFG Consulting put it: *"Our view is that if the Fama-French model is not given any consideration by the AER, 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."*[7] Such a downward bias would prevent the allowed rate of return to be commensurate with the efficient financing costs of the benchmark firm as required by the rules and also not result in a reasonable opportunity for SA Power Networks to recover its reasonable costs of supply.

2 'Cost of Equity in the Black Capital Asset Pricing Model', 22 May 2014, p. 15.
3 'Cost of Equity in the Black Capital Asset Pricing Model', 22 May 2014, p. 2.
4 'Cost of Equity in the Black Capital Asset Pricing Model', 22 May 2014, p. 15.
5 'Cost of Equity in the Black Capital Asset Pricing Model', 22 May 2014, p. 38.
6 'The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses', 6 June 2014, p. 9.
7 'The Fama French Model' 13 May 2014.

Model	Comments
Dividend Discount Model	The Dividend Discount Model approaches the task of estimating the required rate of return in a different way: *"The dividend discount model approach has the advantage of not requiring any assumptions about what factors drive required returns — it simply equates the present value of future dividends to the current stock price. It is also commonly used in industry and regulatory practice. Whereas the Guideline materials identify some concerns with the dividend discount approach, the specification adopted in this report addresses most of those concerns. Consequently, our view is that the dividend discount estimate of the required return is relevant evidence and some regard should be given to it."*[*] This model performs well provided a robust method is used for forecasting future dividends. SFG Consulting has reviewed a range of ways that this model can be implemented, both those generated by or for the AER during the Guideline consultation process and in other publications. The principal issues include how quickly it is assumed that actual level of dividends revert to the long run assumed dividend growth, whether that progression is linear or otherwise and how long term dividend growth is assumed to be related to assumptions about over-all economic growth. SFG Consulting's key conclusions are:[**] • That there should be an eight year transition period over which parameter estimates revert to long term estimates (which is broadly consistent with the AER's '3-stage' model but not its '2-stage' model); • That earnings forecasts and price targets should be drawn from the same analysts rather than using analysts' earnings forecasts and actual stock market prices; • That care should be taken to obtain contemporaneous earnings forecasts and target prices because there are material improvements in reliability compared with earnings and price target data observed at different times; • The term structure considered by Lally that would result in highly variable estimates should not be used; • Changes in share prices for the same stocks over time should be taken into account in the inputs to the model affecting value rather than solely the discount rate (as the AER model does); and • Consistent assumptions are required between the model and the assumptions made concerning dividend imputation.

* 'The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses', 6 June 2014, p. 9
** Alternative versions of the dividend discount model and the implied cost of equity, SFG Consulting, 15 May 2014.

26.3.3 Concerns with the way the Guideline proposes to set the return on equity

For the reasons set out below, the approach to establishing the return on equity set out in the Guideline is not consistent with the NER and is not the best possible estimate of the required rate of return for equity.

We are concerned that the approach set out in the Guideline does not meet the requirements of the new Rules that regard must be had to *"relevant estimation methods, financial models, market data and other evidence"*.

The law recognises that *"an expression such as "have regard to" is capable of conveying different meanings depending on its statutory context."*[164]

The AEMC issued a draft rule determination[165] and a final rule determination[166] without any significant change on this aspect of the then proposed Rules and both these documents assist in understanding the intention of the new provisions:

"The final rule provides the regulator with sufficient discretion on the methodology for estimating the required return on equity and debt components but also ***requires the consideration of a range of estimation methods, financial models, market data and other information so that the best estimate of the rate of return can be obtained overall that achieves the allowed rate of return objective."***[167]

"Ultimately it is important to keep in mind that all these financial models are based on certain theoretical assumptions ***and no one model can be said to provide the right answer."***[168]

This is a case in which the importance given to a "range" of estimation methods, financial models, market data and other information rather than a single source delivering the "right answer" is equivalent to the level of importance given to all the statutory factors in the Gas Code considered in the DBNGP Case and the costs of running the nursing home in the National Health Act considered in the R v Hunt case.[169]

164 Re Dr Ken Michael Am; Ex Parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231, para 55.
165 AEMC Economic Regulation of Network Service Providers Rule Change Draft Determination, August 2012 (AEMC Draft Rule Determination).
166 AEMC Economic Regulation of Network Service Providers Rule Change Final Determination, November 2012 (AEMC Rule Determination).
167 AEMC Rule Determination, p. 8.
168 AEMC Draft Rule Determination, p. 48.
169 R v Hunt; Ex parte Sean Investments Pty Ltd (1979) 180 CLR 322, para 18.

Just as in the DBNGP case, when the AER is asked to consider all the relevant models and other relevant material it is:

"difficult to conceive that it could have been intended that the Regulator might decide to give no weight at all to one or more of the [matters] stipulated" and therefore "the Regulator is required to take the stipulated [matters] into account and to give them real weight as fundamental elements".[170]

When examining the AEMC's rule determination decision, it is clear that the requirement to "have regard" to a range of relevant estimation methods, financial models, market data and other evidence cannot be met by merely considering all the relevant models and then giving weight only to some models and not others. Each "relevant model" needs to contribute to the estimation unless there is a reason to conclude that another model incorporates all of its insights and more.

Nor can it be adequate to elevate a single model as the foundation model and limit the role of all other models to the secondary status of estimating parameters within that foundation model unless there is a proper basis for concluding that they are unsuitable for contributing directly to the return on equity or that the return on equity cannot lie outside those constraints and that the "right answer" must fall within the range of outputs that the foundation model could deliver.

Further, it is relevant to consider the context of the overall regulatory structure into which this new rule has been inserted. The same language requiring "regard" to be had to the full range of relevant inputs now appears in both the new NER and NGR and should be given the same meaning. In understanding the meaning of these words, they need to be understood as both a reform to previous regulatory practice in electricity *and* to previous regulatory practice gas. In this regard, two points from the gas industry are important:

- the AER was already permitted under the previous gas rules to depart from using the SL-CAPM and it could have chosen to use alternative methodologies for setting the return on equity. Network providers had previously proposed other methodologies that the AER had given consideration to but either rejected outright or consigned to a secondary role as a "cross check". The AEMC considered that this approach needed to be reformed to do away with the constraints that concepts such as "well accepted" had placed on the AER. With the taking into account of a broader range of inputs, the AEMC considered that the new rules would achieve their stated aim.
- the NGR are the successor to the National Gas Code (**Gas Code**) and much of the language is inherited from that document. The use of the term "have regard" in the Gas Code was the subject of extensive litigation and the courts construed the term within the context of that document as imposing a requirement on the regulator to give "real weight" to the material and that it was inadequate to consider and give no weight to relevant information.

  Given the prominence of that litigation in the history of the development of the current NGR it is difficult to accept that the AEMC envisaged that it would be sufficient for the AER to consider all the relevant inputs and then give certain of those inputs no probative weight or only a constrained or secondary form of weighting.

The Guideline does not adhere to the requirement to give real weight:

- to the Fama French Model because it is not used at all in the establishment of the return on equity; and
- although weight may be given to the other two models, these other models are each only used to inform one single parameter of the SL-CAPM. Using them in this way severely constrains their ability to have a material effect on the allowed return. Further, even when used to inform a parameter of the SL-CAPM, they are used as secondary evidence that is disregarded to the extent that it is inconsistent with the primary range that is established using a different subset of the available evidence.

Second, instead of applying the rate of return objective, the National Electricity Objective (**NEO**) and the Revenue and Pricing Principles (**RPP**) directly, the Guideline applied a set of extra-legislative criteria[171] for its decision making that resulted in irrelevant considerations being taken into account. The criteria themselves do not appear in the NER or the NEL. They are expressed in such abstract terms that they invite irrelevant considerations to be considered and direct the decision making process away from the matters referred to in the NER and the NEL. In our view, the way in which the AER has applied the criteria have indeed operated in a way that brings irrelevant considerations to bare and is contrary to the requirements of the Rules. Some examples are:

- the criterion that requires that estimation methods and financial models are consistent with "well accepted economic and finance principles" and are "implemented in accordance with good practice" has resulted in a strong preference for conservatism that has resulted in the decision still to be based on the SL-CAPM with secondary weight being given to the DDM and the Black-CAPM only in the limited role of informing certain parameter estimates used within the SL-CAPM and no weight at all being given to the Fama-French Model which is of a substantially younger vintage than the SL-CAPM. This conservatism runs directly counter to the intention of the AEMC[172] that the new Rules do away with the incumbency of the SL-CAPM and open the decision making to the inclusion of all the relevant models and other inputs.

170 Re Dr Ken Michael Am; Ex Parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231, para 55 the "DBNGP Case".

171 Explanatory Statement, p. 24.

172 AEMC Draft Rule Determination, p. 42.

- relatedly, as SFG Consulting points out the AER's propensity to exclude figures that cannot be determined with complete certainty also leads to both under-estimation and improper conservatism:

"The AER's decision to give no weight to the Fama-French model is based upon the rationale that there is uncertainty about what risks are captured by the Fama-French factors, and uncertainty about the magnitude of the risk premiums, and until there is agreement on these issues the model should not be used. If this rationale is accepted there is unlikely to be any new asset pricing model ever adopted."[173]

"Our view is that estimation error is inherent in the cost of equity from all asset pricing models, and estimation error is mitigated by relying on more than one asset pricing model."[174]

The criterion that the choice of inputs should "promote the simple over the complex where appropriate" has been instrumental in the selection of the SL-CAPM as the 'foundation model' even though it is inherent in a requirement to consider all the relevant inputs that a degree of new complexity will emerge.

A further consideration in excluding the Fama-French Model was that the AER considered that there was no clear theoretical foundation to identify the risk factors. This is not a proper basis to exclude a model that in fact performs well empirically in explaining stock market returns. Indeed, there is a lot to be said for giving primacy to empirical performance over theories because, until they are tested against the real word, theories are simply one idea as to how the world may or may not work in practice.

Even if the above AER initiated criteria were relevant to the decision (and SA Power Networks considers that they are not), the AER has misapplied them.

As the attached report from SFG Consulting explains:
- the Fama-French Model is, in fact, well accepted. The body of work of which the model forms a part has gained the highest possible accolade for economics[175], the Chartered Financial Analyst Level II professional accreditation program includes a detailed consideration of this model[176], surveys of practitioners reveal that one or both of the additional factors considered in the model do weigh on the minds of more than a quarter of finance practitioners[177] and the model has been employed by expert testimony relied on by US courts[178].
- theories concerning the risk of financial distress, exposures to changes in expectations for economic growth and asymmetric exposure to market conditions associated with Fama-French's SMB and HML factors each have multiple adherents.[179] In summary:

"The results of Fama and French (1993) led to a substantial body of literature devoted to theoretical reasons for their empirical result. Those theoretical explanations are based upon the asset pricing theories already developed in the 1970s — the intertemporal CAPM and the arbitrage pricing theory. Some of those theories and associated empirical evidence are presented in this paper, and this is not an exhaustive list. To conclude that the Fama-French model is without theoretical foundation is incorrect. It is not appropriate to dismiss the theoretical underpinnings of the model merely because the empirical result was observed first."

It is also notable that the criteria have not been applied uniformly. For instance:
- in adopting a multiple step process in which there are three classes of model — a 'foundation model', secondary models used to establish inputs for the foundation model and models that are not given any weight, the Guideline seems to have lost sight of the criterion that the choice and combination of models should "promote simple over complex approaches".
- the "fit for purpose" criterion includes the notion that each model should be employed in a manner that is "consistent with the original purpose for which it was compiled". The DDM and Black-CAPM models were developed as stand-alone models in their own right for explaining stock market returns, not models that were originally compiled for use in setting particular parameters within the SL-CAPM in a way that is not "consistent with their original purpose".

Third, the concept of adopting a 'foundation model' is not found in the NER or NEL. Elevating any one model to that status necessarily gives it primary weight and less weight to all the other models. Such an approach gives undue weight to the foundation model and constrains the regard that is had to those other models, contrary to the requirements of the Rules.

Fourth, the way in which the Guideline proposes to combine or supplement the use of the SL-CAPM with the DDM and Black-CAPM models does not properly engage with the nature of the acknowledged flaws of the SL-CAPM. In particular the SL-CAPM model is known to deliver downwardly biased estimates of required returns for low beta firms and value stocks — both of which are characteristics that would apply to the benchmark efficient entity. By establishing a range of SL-CAPM results and using the DDM and Black-CAPM only to select a figure within that range, the downward biases of the SL-CAPM are still operating as a constraint upon the rate of return selected notwithstanding the results of the other models. As noted in the table above, there is also a problem combining a static long run average MRP estimate with a current return on government debt as the estimate of the risk free rate.

173 'The Fama French Model', p. 3.
174 'The Fama French Model', p. 24.
175 'The Fama French Model', p. 17.
176 'The Fama French Model', p. 19.
177 'The Fama French Model', pp. 20–21.
178 'The Fama French Model', p. 22.
179 'The Fama French Model', pp. 30–32.

26.3.4 Overview of SA Power Networks' proposed approach to determining the return on equity

SA Power Networks considers that the much safer and direct way in which to apply the new NER and the NEL requirements to have regard to all the relevant inputs is to simply:

- identify the relevant evidence which may be used to estimate the parameters within each of the relevant return on equity models;
- estimate model parameters for each relevant return on equity model, based on relevant market data and other evidence;
- separately estimate the required return on equity using each of the relevant models; and
- synthesise model results as a weighted average of the individual estimates.

The weightings take account of the expert report from SFG Consulting that:

- explains the extent to which the models are independent of each other or are variations of each other;
- takes into account the nature of the acknowledged weaknesses of the models and in particular whether the weaknesses result in the model giving a biased or unbiased estimate for the benchmark efficient entity; and
- tests whether the weightings are unduly sensitive to adjustments in the weightings accorded to the different models.

Evidence based parameter selection

Between them, the four models require estimates of the following parameters:

- a risk free rate of return;
- a required rate of return on the market portfolio (or an MRP to combine with the risk free rate);
- an equity beta (for the two CAPM models);
- a zero-beta return (for the Black-CAPM), or zero-beta risk premium;
- market exposure, size and book to market factors (Fama-French Model only); and
- a risk premium for comparable firms (for use with the DDM only).

The proposed source of each of these parameters is discussed below.

Risk Free Rate Averaging Period

SA Power Networks accepts the approach to setting the risk free rate proposed in the Guideline which is to select a 20 business day averaging period agreed with the AER that will remain confidential until the period has passed. For illustrative purposes, the figures presented in this proposal are calculated using a 20 business day period ending on [29 August 2014].

Accompanying this Proposal and forming part of it is a confidential letter proposing an averaging period for the setting of the risk free rate.

Required return on the market portfolio (or its corollary, the market risk premium)

A number of the models include a MRP which is simply the required return on the market portfolio less the risk free rate. In the past the AER has adopted the approach of using long run average excess returns (ie, the returns of a representative portfolio above the risk free rate) which is how Ibbotson calculates an MRP, but there are other ways to estimate an MRP including historical data using an approach championed by Wright, the estimates derived from a dividend growth model, and estimates from independent experts and surveys.

SFG have noted that the Ibbotson approach involves adding an effectively constant MRP to the contemporaneous risk-free rate produces an estimate of the required return on equity that varies one-for-one with changes in the risk-free rate. They note that:[180]

"The Ibbotson approach implies that equity is more expensive than average during economic expansions and bull markets (the late 1990s and mid 2000s) and cheaper than average during financial crises (the pronounced reduction in 2008)."

It is counter-intuitive that the required return on equity should be lower during financial crises than during economic expansions, and this should be taken into account when the AER considers how to best use the historical data to inform their estimate of MRP. In the Guideline, the AER uses historical data only via the Ibbotson approach (which leads to the counter-intuitive results described above) and places no weight on the Wright method for processing the historical data. By contrast, SFG recommend that both methods provide relevant evidence in which case both should be given some regard.

The Guideline proposes that the AER would consider all this material and determine an MRP using 'regulatory judgement'. The Guideline provides a worked example as at December 2013 but the AER would not necessarily exercise judgement in the same way in our Proposal. We consider that there are a number of flaws in the worked example as detailed by SFG Consulting. The detailed analysis is summarised as follows:

"[I]n some places the Guideline relies on dated evidence that has now been updated, in other places it relies on inaccurate data that has since been corrected, and in other places it makes improper comparisons (eg, where estimates that include the benefit of imputation credits and estimates that exclude the benefit are compared as equals)." [181]

Instead our Proposal adopts SFG Consulting's view as to the most appropriate manner in which the AER should exercise judgement to establish the MRP. Largely it uses the same universe of information, although certain information (such as inherently unreliable surveys) are not used. There are, however, other important differences in the details of how the other sources would be used to correct for the flaws that SFG Consulting have summarised above. SFG Consulting have prepared an update of their calculations in

180 'The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses', 6 June 2104, p. 56.
181 'The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses', 6 June 2104, p. 44.

a new report.[182] In summary, the text of the original report with the updated figures is as follows:

"[SFG Consulting would] have regard to the following evidence:

> *a) First, we note that historical returns can be processed in two ways — by assuming that MRP is constant in all market conditions (Ibbotson approach [currently estimated by SFG Consulting to be 6.63%]) or by assuming that real required returns are constant in all market conditions (Wright approach [currently estimated by SFG Consulting to be 8.28%]). We apply equal weight to each of these approaches, producing an estimate of MRP from historical returns of [7.45%];*
>
> *b) The estimate of MRP from dividend discount models of [7.99%] [which is drawn from a companion report by SFG Consulting]; and*
>
> *c) The estimate of MRP from independent expert reports of 7.01%."[183]*

The same report illustrates why the outcome is not very sensitive to the weightings given to the three sources. The relevant evidence is discussed in detail in the report. In summary it comprises the following (each grossed up for a theta estimate of 0.35):

- a historical average of excess returns above the contemporaneous risk free rate from 1883 to 2013 (which delivers an average of [6.63%]) added to the current risk free rate (ie, [3.43%]) to deliver an estimate of [10.06%];
- a historical average market return using the Wright approach to deliver an estimate of [11.71%];
- a DDM estimate to deliver an estimate of [11.42%]; and
- independent expert valuation reports to deliver an estimate of [10.44%].

SFG Consulting synthesises this information to provide a single point estimate of [11.15%] as the mid-point between the first two of the above historical estimates which is also a figure that is very similar to the other two estimates.

The other inputs suggested in the Guideline are not used because there are no reliable surveys upon which to rely and we consider recycling past regulatory decisions does not provide any additional insight to prevailing market conditions.

Equity beta

We consider the reduction of the equity beta from 0.8 to 0.7 proposed by the Guideline to be incorrect on the basis of the following considerations emerging from work undertaken by SFG Consulting:[184]

"a) The estimate of 0.7 is the outcome of a convoluted multi-stage approach whereby:

> *i) a sub-set of the relevant evidence … is used to constrain the range of possible estimates to 0.4 to 0.7;*
>
> *ii) the other relevant evidence that is considered in the Guideline … all supports an estimate above 0.7, but the first stage of the process constrains the maximum estimate to be 0.7; and*
>
> *iii) there is relevant evidence that is not considered in the Guideline …;*

b) The subset of evidence that is used to produce the constraining range of 0.4 to 0.7 is not sufficiently reliable to be used for that purpose because: the beta estimates vary wildly … across firms; … over time; … depending on which sampling frequency is used; … depending on which regression specification is used; and … depending on the day of the week and month on which they are computed;

c) The evidence from international comparable firms suggests an equity beta materially above 0.7;

d) To the extent that the 0.7 estimate has been influenced by the AER's conceptual analysis, it is wrong. The AER concludes that the conceptual analysis supports an equity beta materially below 1, but it does not. In this regard:

> *i) The Frontier Economics (2013) report does not support an equity beta below 1 … ; and*
>
> *ii) The McKenzie and Partington (2012) report sets out two pieces of empirical evidence. One suggests that energy networks have equity betas materially above one, and the other suggests that finance risk is the primary component of beta for utilities;*

e) To the extent that the 0.7 estimate has been set to match the equity beta that the ACCC uses for water utilities, it is wrong. Regulatory estimates of beta for water utilities are based on regulatory estimates of beta for energy networks (which introduces circularity) and on international water utilities … ."

The modelling of the equity beta is also flawed in that the sample is too small and the estimate too variable in response to the choice of statistical method. Irrelevant water utility data is included instead of relevant international data on the energy network sector.

SFG Consulting's expert opinion[185] is that the most appropriate estimate for the equity beta is [0.82] on the following basis:

"One way of having regard to the range of relevant models and evidenced is to estimate the required return on equity under each of the relevant approaches and then to determine an allowed return on equity after having regard to the relative strengths and weaknesses of each approach. Under such a multi-model approach, we would adopt a Sharpe-Lintner

182 'Updated estimate of the required return on equity', 8 September 2014.
183 'The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses', 6 June 2104, p. 6.
184 'Equity Beta', 12 May 2014, p. 10.
185 SFG Consulting, 'Equity beta', Report for Jemena Gas Networks, ActewAGL and Networks NSW, May 2014, p. 4.

CAPM beta of 0.82 — the raw estimate of beta that does not reflect any evidence other than the historical statistical relationship between stock returns and market returns for the relevant set of comparable firms."[186]

Return on a zero beta asset
SFG Consulting have estimated the return on a zero beta asset by adding a [3.34%] zero beta premium to the risk free rate of [3.43%] to give an estimated return of [6.77%] return on a zero beta asset.

This is within the reasonable range in the Guideline and for that reason this issue does not warrant a detailed treatment in this Proposal.

Fama-French Model market exposure, SMB and HML factors
Because the Guideline does not use the Fama-French Model, there is no relevant departure from the Guideline in relation to these factors.

Recent regressions conducted by SFG Consulting have concluded that the best estimates for the three relevant Fama-French Model factors are:

- market exposure: [5.11%];
- size exposure: [-0.19%]; and
- book to market exposure: [1.15%].

The attached report fully substantiates these figures.[187]

Risk premium for use in the DDM
SFG Consulting has estimated the risk premium for relevant comparable firms at 94% of the over-all market returns.

Four modelled estimates for the return on equity based on the above parameters
Using the above parameter estimates, SFG Consulting[188] has prepared estimates for the four relevant equity models of:

- SL-CAPM: [9.74]%
- Black-CAPM: [10.35]%
- Fama French Model: [10.57]%
- DDM: [10.72]%

A single point estimate derived from the outputs of the four relevant equity return models
As explained above, we do not accept that using the SL-CAPM to constrain the estimate of equity returns enables proper regard to be had to the point estimates delivered by the Black-CAPM and the DDM.

Nor should the three factor insights of the Fama-French Model be disregarded when establishing a single point estimate for the return on equity.

Instead, the better way to have regard to all the relevant information is to establish a weighted average of the four estimates. One way to do this would be to weight all four estimates equally but SFG Consulting points out that:

- the two CAPM estimates rely on common theoretical elements and to give them each the same weighting as the other two models could be viewed as according the common theoretical elements double weighting.
- the two CAPM differ, however, in that the Black-CAPM delivers an estimate of the intercept while the SL-CAPM delivers a lower bound.

Therefore, SFG Consulting recommends[189] using the following weights:

- 25% to the DDM and 75% to the three asset pricing models;
- half of the 75% should be accorded to the Fama-French Model (ie, 37.5%);
- the remaining 37.5% assigned to the capital asset pricing models should be divided two thirds to the Black-CAPM (which provides an estimate of the intercept — ie, 25%) and one third to the SL-CAPM (which provides a lower bound to the intercept — ie, 12.5%).

On that basis, the single point estimate for the required return on equity would currently be 10.45%.

26.3.5 An alternative approach through minimum necessary amendments to the Guideline

We do not agree with the approach in the Guideline that an estimate for the return on equity can be generated using the SL-CAPM as a 'foundation model' (or indeed any foundation model) that meets the requirements of the NER. Nonetheless, we have asked SFG Consulting to consider what amendments could be made to the approach to compensate for its faults.

As discussed above, two significant flaws in the SL-CAPM are that it is downwardly biased for low beta assets and value assets. SFG Consulting[190] has separately estimated three CAPM equity betas using each of the other models to correct for these biases. The Black-CAPM in particular addresses the issue of the bias for low beta assets, the Fama French Model addresses the issue of the bias for value assets and the DDM uses contemporaneous evidence.

The weighted average of the betas delivered in this way is [0.91].

SFG have also estimated the required return on the market to be [11.15%] as at [29 August 2014].

For a risk-free rate of 3.43%, an asset with a beta of [0.91], and an over-all required rate of return for the market of [11.15%], SFG Consulting calculate the required return on equity using the SL-CAPM model of [10.45%].[191]

186 'Equity Beta', 12 May 2014, p. 42.
187 'The Fama-French Model' 13 May 2014.
188 'The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses', 6 June 2014, p. 91.
189 'The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses', 6 June 2014, pp. 89–90.
190 'The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses', 6 June 2014, pp. 92–96.
191 Note that the final estimate of the required return is computed by aggregating parameters measured to many decimal places since a calculation based on several parameters, each rounded to only two decimal places would introduce unnecessary rounding error.

26.4

The value of imputation tax credits

26.4.1 Summary

Gamma (γ) is defined in the NER as "*the value of imputation credits*" and theta is defined as the market value of imputation credits distributed via a dividend.[192]

SA Power Networks considers that it is clear that what is required under the NER is an estimate of the value of imputation credits to investors in the business. This interpretation is consistent with the broader regulatory framework and the task set by the NER to determine total revenue, as well as past regulatory practice, and previous decisions of the Tribunal.

This is also the interpretation that best achieves the NEO, as it ensures that the adjustment for imputation credits in the taxation building block properly reflects the actual value of imputation credits to investors, not merely their notional face value or *potential value*. Accounting for gamma in this way ensures that the overall return received by investors (including the value they ascribe to imputation credits) is sufficient to promote efficient investment in, and use of, infrastructure, for the long-term interests of consumers.

SA Power Networks proposes to calculate gamma in the orthodox manner, as the product of:

- the distribution rate (ie the extent to which imputation credits that are created when companies pay tax, are distributed to investors); and
- the value of distributed imputation credits to investors who receive them (referred to as theta).

SA Power Networks proposes a distribution rate of 0.7, which is consistent with the Guideline. Recent empirical evidence also continues to support a distribution rate of 0.7.

SA Power Networks proposes a value for theta of 0.35. The reasons why SA Power Networks is proposing a different value for theta to that in the Guideline include:

- SA Power Networks does not agree with the 'conceptual framework' adopted by the AER for estimating theta, and in particular the focus on utilisation evidence, rather than market value evidence. The AER's approach is not consistent with the NEO. It does not measure the required return for the purposes of promoting efficient investment, and would lead to under investment;
- in order to provide an acceptable overall return to equity holders, theta must be estimated as the *value* of distributed imputation credits to equity-holders. This is the conventional and orthodox approach to estimating theta. It is also the approach which best gives effect to the NEO, as it provides for recognition of the value to equity-holders of imputation credits and provides for overall returns which promote efficient investment;
- there are compelling reasons why the benefit of imputation credits, which is the amount by which the allowable return otherwise calculated in accordance with the NER should be reduced, is significantly less than the face value of imputation credits or the utilisation of imputation credits. However, these were not considered in the Guideline;
- the value for theta proposed by SA Power Networks accords with what one would expect to be the additional benefit conferred by the system of imputation credits. The value of theta proposed in the Guideline does not;
- there are overwhelming problems with the taxation statistics and other forms of evidence given primary emphasis in the Guideline. They are, and are well recognised to be, simply unreliable. Further, a key piece of evidence used by the AER (Handley and Maheswaran (2008)[193]) is not an empirical study at all (because the data was not available), but merely involves an assumption of full utilisation by domestic investors; any reliance upon it involves obvious error;
- the only source of evidence capable of providing a point estimate for the value of distributed imputation credits to investors is market value studies. Evidence of utilisation rates (or potential utilisation rates, as indicated by the equity ownership approach) can only indicate the upper bound for investors' valuation of imputation credits. The conceptual goalposts approach referred to by the AER provides no relevant information on the actual value of credits;
- the best estimate of investors' valuation of imputation credits from market value studies is 0.35.

Multiplying a distribution rate of 0.7 with a theta estimate of 0.35 produces a value for gamma of 0.25.

SA Power Networks' reasons for proposing a different value for theta to that in the Guideline are elaborated below.

26.4.2 Introduction to Gamma

In regulating the allowed rate of return for energy network businesses, one of the most contentious issues is the treatment of imputation credits (gamma). When the Tribunal considered the appeal to SA Power Networks' last 2010 Determination, it stated that:

"The Tribunal has found some deficiencies in its understanding of the foundations of the task facing it, and the AER, in determining the appropriate value for gamma. These issues have not been explored so far because they have not arisen between the parties who appear to be in agreement about how the Rules should be interpreted regarding the treatment of corporate income tax. They may best be left until the next WACC review. Indeed, they may go to the basis for the Rules themselves.

The Tribunal would be assisted in its consideration of the issues before it if the AER were to provide relevant extrinsic material explaining:

192 P. H. L. Monkhouse, 'Adapting the APV valuation methodology and the beta gearing formula to the dividend imputation tax system', Accounting and Finance 37 (1997) 69–88, at 72, 74. See also: Monkhouse (1996) and Monkhouse (1993).

193 John C Handley and Krishnan Maheswaran, 'A Measure of the Efficacy of the Australian Imputation Tax System', The Economic Record, Vol 84, No 264, March 2008.

(a) the rationale for including the gamma component in the formula for calculating the estimated cost of corporate income tax; and

(b) how it relates to the rest of the building blocks, especially the rate of return …".

To understand this aspect of the regulatory framework, we start by explaining the reasons why gamma exists and the role it plays in the decision concerning permitted returns.

Investors derive their total expected return from after tax profit and the value of imputation credits. A regulated entity should only recover sufficient revenue to allow it to earn the expected return from after tax profit. Regulated revenue is calculated from building block costs which includes return on equity allowance and tax allowance. The regulated return on equity allowance reflects the total expected return from after tax profit and value of imputation credits.

To avoid double counting, the value of imputation credits is deducted from the tax allowance. The examples which follow demonstrate that for a regulated equity investment of $700 with an expected total return on equity of 10%, the expected $70 return is paid in two components:

- $6.77 arising from the value of imputation credits; and
- $63.23 arising from after tax profit earned on the regulated asset.

Example 1: Non-imputation setting

Consider a firm with $700 of equity in its RAB and an allowed return on equity of 10%. In the absence of dividend imputation, such a firm would require an after-tax profit of $70 to distribute to its shareholders. This would require a pre-tax profit of $100, as set out in the table below.

Table 26.4: Non-imputation setting

Profit before tax	100
Less corporate tax	30
After-tax profit available for distribution to shareholders	70

In general, in the absence of dividend imputation, a pre-tax profit of $X will generate an after-tax profit (available for distribution to shareholders) of $X(1-T) where T is the corporate tax rate. In this case, the required pre-tax profit can be determined by solving:

$X(1 - 0.3) = 70,$

where X is $100 in this case.

That is, the regulator would allow the firm to charge prices so that the expected pre-tax profit is $100, in order that there would be $70 of after-tax profits available to shareholders, as required.

Note that the $70 benefit that the shareholders receive from the after-tax profit is independent of the firm's payout policy. For example, suppose the firm distributes a dividend of $50 and retains $20 to fund future investment. If the invested funds earn a normal return, the value of those investments will be $20. That is, whatever is not distributed as a dividend increases the value of the firm by an equivalent amount.

Example 2: Imputation setting

Now consider the case with imputation. We consider the same firm as above with $700 of equity capital and an allowed return of 10%. In the regulatory setting, the allowed return on equity includes the value of imputation credits — it represents the total return required by shareholders, a portion of which is assumed to come in the form of imputation credits.

By way of example, suppose gamma is set to 0.25. In that case, a $100 pre-tax profit produces the same $70 after-tax profit for distribution to shareholders. It also produces imputation credits with a face value of $30 (equal to the amount of corporate tax paid). For gamma set to 0.25, the value of those imputation credits is 0.25 x 30 = 7.5. Thus, the total return to shareholders is the sum of the $70 after-tax profit and the $7.5 of value from imputation credits, as set out in the table below.

Table 26.5: Imputation setting

Profit before tax	100
Less corporate tax	30
After-tax profit available for distribution to shareholders	70
Value of imputation credits	7.5
Total return to shareholders	**77.5**

In general, a pre-tax profit of $X will generate an after-tax profit for shareholders of $X(1-T) plus imputation credits valued at yTX. In this case, a pre-tax profit of $100 produces an after-tax profit for distribution to shareholders of:

$100(1 - 0.3) = 70$

and imputation credits with a value of:

$yTX = 0.25 \times 0.3 \times 100 = 7.5$

In summary, a pre-tax profit of $X produces a return to shareholders of:

$X(1 - \mathrm{T}) + yTX$

which can also be written as:

$X(1 - T(1 - y))$

In the example above, a pre-tax profit produces a total return to shareholders of:

$100(1 - 0.3(1 - 0.25)) = 77.5$

This is more than the $70 return that is required by shareholders of a firm with $700 of equity capital and an allowed return on equity (including imputation credits) of 10%. In this case, the correct pre-tax profit is determined by solving:

$$X(1 - 0.3(1 - 0.25)) = 70 \qquad (1)$$

In this case, the required pre-tax profit is $90.32. This produces an after-tax profit for shareholders of $63.23 and imputation credits with a value of $6.77 — a total of $70, as set out in the table below.

Table 26.6: Imputation setting adjustment

Profit before tax	90.32
Less corporate tax (30%)	27.10
After-tax profit available for distribution to shareholders	63.23
Value of imputation credits (0.25 times corporate tax paid)	6.77
Total return to shareholders	**70.00**

Estimated tax cost
The NER define the Estimated Tax Cost (ETC)[194] as:

$$ETC = (ETI \times r_t)(1 - y)$$

where ETI is the estimated taxable income (90.32 in the above example) and r_t is used to represent the corporate tax rate (30% in the above example). That is, the expected tax cost in the above example is:

$$ETC = (90.32 \times 0.3)(1 - 0.25) = 20.32 \qquad (2)$$

This calculation recognises that the firm pays corporate tax of 27.10, which is offset by the value that shareholders receive from imputation credits, 6.77 (ie, 27.10 - 6.77 = 20.32, with rounding).

In its PTRM, the AER combines Equations (1) and (2) above. This enables the calculation of the expected tax cost as:

$$ETC = \underset{\text{ex - imputation credits}}{\text{Required return on equity}} \times \frac{T}{1 - T(1 - y)} \qquad (3)$$

In the above example, we have:

$$ETC = 70 \times \frac{0.3}{1 - 0.3(1 - 0.25)} = 27.10$$

as set out in Row 44 of the Analysis sheet of the PTRM.

The PTRM then computes the value of imputation credits by multiplying the corporate tax payment gamma at Row 43 of the Analysis sheet of the PTRM. In the example above, this is:

$$27.10 \times 0.25 = 6.77$$

The required pre-tax profit is then determined as:

$$\begin{aligned} \textit{Pre-tax profit} &= \textit{After-tax profit} + \textit{ETC} - y \times \textit{ETC} \qquad (4) \\ &= 70 + 27.10 - 6.77 = 90.32 \end{aligned}$$

exactly as set out above. This calculation is performed at Row 27 of the Analysis sheet of the PTRM.

Returns with and without imputation credits
In the above example, shareholders require a total return (including imputation credits) of 10%, which amounts to $70 for equity capital of $700. The $70 return is paid in two components:

- imputation credits comprise $6.77 of the $70 total. This amounts to 9.68% of the total; and
- the firm is allowed to charge prices that enable it to achieve an after-tax profit for the shareholders of $63.23, which amounts to 90.32% of the total.

Officer (1994)[195] has previously shown that the proportion of the total return that comes from after tax profits (ie, not including the value of imputation credits) is:

$$\frac{1 - T}{1 - T(1 - y)}$$

which, in the above example is:

$$\frac{1 - 0.3}{1 - 0.3(1 - 0.25)} = 90.32\%$$

Similarly, Officer (1994) has also previously shown that the relationship between the with-imputation return and the ex-imputation return is given by:

$$r_{ex} = r_{with} \frac{1 - T}{1 - T(1 - y)}$$

In the above example, we have:

$$r_{ex} = 10\% \frac{1 - 0.3}{1 - 0.3(1 - 0.25)} = 9.032\%$$

Note that the return from after-tax profits is $63.23, which amounts to a return of 9.032% on the $700 of equity capital.

Calculations in the Australian regulatory framework
The Australian regulatory framework, and the AER's PTRM in particular, begin with an estimate of the total (with-imputation) required return on equity (10% in the above example). From this, the PTRM computes the total required return to equity ($70 in the above example).

The PTRM then computes the pre-tax profit (X in the equation below) that would be required to produce the required return to equity by solving:

$$X(1 - T(1 - y)) = \text{Total required return to equity}$$

194 NER Clause 6.5.3.

195 R. Officer, 'The cost of capital of a company under an imputation tax system', Accounting and finance, May 1994, vol. 34(1).

In the example above, a pre-tax profit of $90.32 produced an after-tax profit for shareholders of $63.23 and imputation credits with a value of $6.77 — making up the $70 total required return.

The regulator then sets prices to produce the required pre-tax profit ($90.32 in the above example).

The starting point for these calculations is an estimate of the with-imputation required return on equity. Consequently, any approach that produces an estimate of the ex-imputation required return on equity must first be converted to a with-imputation required return on equity for use in the Australian regulatory framework (and the AER's PTRM in particular). As set out above, converting between ex-imputation and with-imputation required returns is straightforward, as shown by Officer (1994):

$$r_{ex} = r_{with} \frac{1 - T}{1 - T(1 - y)} \qquad (5)$$

For example, the New South Wales Independent Pricing and Regulatory Tribunal (**IPART**) uses a number of versions of the DDM to inform its estimate of the required return on equity. The dividend discount approach takes no account of imputation credits at all, and consequently produces an estimate of the ex-imputation required return on equity. IPART uses the Officer formula set out above to convert the ex-imputation estimate into a with-imputation estimate, for use in the regulatory model.

In summary, IPART and the PTRM both convert between the with-imputation and ex-imputation required return on equity using the Officer (1994) formula in Equation (5) above.

26.4.3 Definition of gamma

Rule requirements

Clause 6.5.3 of the NER requires an estimate of y (gamma), being *"the value of imputation credits"*.[196]

Prior to changes to the NER which took effect in November 2012, gamma was defined as *"the assumed utilisation of imputation credits"*. This term in the NER was widely understood to be, and applied by regulators as, the value equity shareholders place on distributed imputation credits.[197] However, as part of the package of amendments to the NER in November 2012, this was clarified by amending the definition of gamma to be the *value* rather than *assumed utilisation* of imputation credits.

The way in which the NER was changed does not suggest that the AEMC was in any way concerned or dissatisfied with how the estimation of gamma had previously been approached. On the contrary, the change made by the AEMC appears to have been directed at better aligning the language of the NER with accepted orthodox regulatory practice. Certainly, there is nothing in the explanatory materials accompanying the Rules change which indicates that there was intended to be a fundamental change in the way gamma (and particularly theta) is estimated.

If any party (including the AER) had been concerned about how the estimation of gamma had previously been approached, it would have been open to them to propose a more fundamental change to the Rules around gamma and/or the calculation of corporate income tax building block more generally. However this was not done.

As will be discussed further below, in the broader context of the NER, and construing the term in line with the objectives of the legislative framework in which it sits, it makes sense that what is relevant is the value that equity holders place on imputation credits, as opposed to simply their face-value or utilisation rate. What the NER are clearly directed at is — consistent with the NEO and the revenue and pricing principles — providing the opportunity to recover at least efficient costs, including a return to equity holders. What is relevant in the context of the broader objectives of the NER is the *value* of imputation credits to equity holders.

The way in which imputation credits are accounted for in the building block framework will ultimately impact upon returns for equity-holders. As such, it is critical that what is taken into account is the value of imputation credits to equity-holders, not just their face-value or utilisation rate. Further, it is important that the value for gamma is estimated consistently with values for other rate of return parameters.

Construing the term "value of imputation credits"

SA Power Networks considers that the words *"value of imputation credits"* have a clear and unambiguous meaning. We consider that the reference to value of imputation credits is clearly referring to the value to equity-holders of imputation credits that are distributed by the business.

The AER has suggested in the Guideline that "value" could *"be used in a generic sense to refer to the number that a particular parameter takes (that is, its numerical value)"*.[198] If the word "value" was being used in that sense, then the appropriate phrase would be the "value for imputation credits". Such a phrase would be meaningless and provide no assistance in understanding the meaning of gamma. By contrast, the use of the words "value of" indicates that the term has its ordinary meaning — the value of something is its worth. The interpretation in the Guideline clearly is an incorrect interpretation of the rule. To apply that incorrect interpretation of the rule would involve legal error. However to the extent that there are possible alternative interpretations of the words *"value of imputation credits"*, the NEL requires that the interpretation that will best achieve the purpose or object of the NEL is to be preferred to any other interpretation.[199]

196 NER clause 6.5.3.
197 For example, in its 2009 WACC Review Final Decision, the AER referred to gamma as representing the 'value for imputation credits', noting that 'Standard regulatory practice in Australia is to incorporate a value for imputation credits in determining the appropriate company tax allowance (the 'corporate income tax building block') to include in the required revenues of regulated businesses' (AER, Final Decision: Electricity transmission and distribution network service providers — Review of the weighted average cost of capital (WACC) parameters, May 2009, p. 393).

198 AER, Explanatory Statement: Rate of Return Guideline, December 2013, Appendix H, p. 150.
199 NEL, Schedule 2, item 7(1).

The object of the 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 price, quality, safety, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system.[200] The relevant secondary materials make clear that the NEO is 'an economic concept', which at its core seeks to promote economic efficiency. The second reading speech accompanying the introduction of the NEO states:

"The market objective is an economic concept and should be interpreted as such. For example, investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities.

The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised."[201]

Accordingly, to the extent that the words *"value of imputation credits"* could be susceptible to more than one meaning, the meaning that is more likely to promote economically efficient investment in, and use of, electricity services ought to be preferred.

SA Power Networks considers that in order to promote efficient investment in, and use of, electricity services, the words *"value of imputation credits"* must be interpreted as the value to equity-holders of imputation credits that are distributed by the business. In the context of determining an adjustment to the corporate income tax building block to account for imputation credits, what is relevant is the value that equity-holders place on those credits, since this is what impacts on the overall return they receive on their investment, and ultimately, incentives to undertake efficient investment. If the value for gamma is set higher (or lower) than the actual value to investors of imputation credits, then the discount applied to the tax building block will overstate (understate) the value to investors of imputation credits, meaning that overall after-tax returns will be too low (or too high), which will lead to over or under investment.

This can be illustrated by the following simple example. If investors require an annual after-tax return of $70 to invest in a particular business, the level of pre-tax return that is required to promote efficient investment would be $100, if there is no value assigned to imputation credits. However, if investors assign a positive value to imputation credits, the level of pre-tax return that is required to promote efficient investment would be somewhat less than $100, depending on how much value is assigned to those credits — for example, if investors assign a value to credits representing 25% of the total face value of all credits generated by the business (gamma of 0.25), the required pre-tax return would be reduced to $90.32.

200 NEL, s 7.
201 South Australia, Parliamentary Debates, Legislative Council, 2 March 2005, 1303 (P Holloway).

The table below illustrates the implication of assigning a value to imputation credits which does not reflect the value actually placed on credits by investors in the business. Clearly, if the value that is assigned to gamma is higher than the value actually placed on credits by investors in the business, the level of pre-tax returns will be below what is required to promote efficient investment.

Table 26.7: Example of gamma impact on overall returns

	Required returns, based on actual value of imputation credits to investors (assume value of 0.25)	Required returns, based on higher value of imputation credits to investors (assume value of 0.5)
Required post-tax return	$70.00	$70.00
Company tax	$27.10	$24.71
Less value of imputation credits to investors	$6.77	$12.35
Required pre-tax return	$90.32	$82.36

It is therefore critical that the value for gamma accurately reflects the value of imputation credits to investors, not just their face value or the rate at which they are redeemed. This is the only interpretation of the term 'gamma' which properly gives effect to the statutory objective of promoting efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers. Any other approach would result in the business not being properly compensated for the overall return required by investors, which would in turn lead to inefficient investment.

This approach to interpretation is consistent with the approach taken with other elements of the return on capital. For example, the return on debt is estimated by reference to the returns actually required by investors, as reflected in market prices for the relevant securities. Consistent with this, any offsetting adjustment to the overall return received by investors to account for imputation credits must reflect the value actually ascribed by investors to those imputation credits, not their notional maximum value or nominal face value.

Components of gamma — the Monkhouse formula

The generally accepted method for calculating gamma is using the Monkhouse formula. This is the approach that has been used by the AER in the past, and which continues to be used by all Australian economic regulatory authorities.

Under the Monkhouse formula, gamma is the product of:

- the credit payout ratio (or distribution rate); and
- *"the utilisation factor"*, which Monkhouse defines as measuring *"the market value of imputation credits distributed via a dividend"* (theta).[202]

202 See footnote 192.

This formulation of gamma is widely accepted, including by the AER and SA Power Networks. As will be discussed below, the only area of disagreement is in relation to estimation of theta.

Previous AER/Tribunal approach to measuring gamma, and that of other regulators

Prior to issuing its Guidelines, the AER had taken a highly orthodox approach to estimating gamma. The AER's approach had involved:

- estimating the distribution rate by reference to the observed economy-wide distribution rate, as indicated by Australian Tax Office (ATO) data; and
- estimating theta as the value of distributed credits to investors.

This previous approach of the AER reflected a correct interpretation of the role of gamma in the building block framework under the NER, as it provided for an estimate of the value of distributed imputation credits to investors. This approach (when properly applied) provided for an overall return to investors which promoted efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers.

The AER's previous approach followed the approach taken by the Tribunal in its May 2011 decision in *Energex*.[203] In that decision, the Tribunal had determined a value for gamma of 0.25, reflecting evidence of the economy-wide distribution rate (0.7) and the market value of distributed credits, as indicated by dividend drop-off analysis (0.35).[204]

AER revised position in the Guideline

In its Explanatory Statement, the AER proposes to take a new approach to determining gamma, based on a new 'conceptual framework'. The AER states that it has *"re-evaluated the conceptual task of estimating the value of imputation credits"*.[205] The AER then seeks to redefine gamma as *"an estimate of the expected proportion of company tax which is returned to investors through utilisation of imputation credits"*.[206]

The AER then goes on to determine a value for gamma principally by reference to information on utilisation/redemption rates. As will be discussed further below in relation to theta, while the AER says that it relies on several sources of evidence including market value studies, only two pieces of evidence appear to be given any material weight. The two pieces of evidence that are given material weight are utilisation rates from tax statistics, and the "equity ownership approach", which indicates the maximum[207] proportion of investors that are <u>eligible</u> to redeem or utilise credits (these are the only two sources of evidence for which the AER's estimate of theta falls within the range of values indicated by the evidence).

Thus, although the AER states that it is assessing *"an estimate of the expected proportion of company tax which is returned to investors through utilisation of imputation credits"*, based on the way in which the AER estimates this parameter in the Guideline, we understand the AER to be interpreting gamma as a measure of the proportion of total company tax payments accounted for by imputation credits that are <u>redeemed</u>, or that <u>can be redeemed</u>, by investors. In relation to this latter aspect, in effect the AER is seeking to answer the question: *"out of total company tax payments, what proportion is accounted for by the total face value of all imputation credits which can be redeemed?"*.

This new AER approach represents a significant departure from the approach taken by the Tribunal in *Energex*, and the approach of the AER both prior to and following that Tribunal decision.[208] The AER's new approach also represents a very significant departure from orthodox regulatory practice.

Orthodox regulatory practice has been to measure the <u>value</u> of imputation credits, not simply the proportion that can be <u>redeemed</u>. Orthodox practice has also recognised that the value of imputation credits will not be the same as the face value of those credits that are redeemed or that can be redeemed. Rather, the face value of redeemed utilised credits will provide no more than an upper bound for the true value to equity-holders. As will be discussed further below, there are several reasons why it cannot simply be assumed that the value of imputation credits will equal the face value of all credits that are redeemed. On the contrary, there is strong evidence (set out below)

203 Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9.

204 Although we do not consider the decisions of other regulators to be a basis for decision making, the Guideline does propose to give a degree of weight to such decisions. We note, therefore, that the ERA explained its approach to gamma as "[a]ny value generated by the presence of franking credits in the Australian tax system must be accounted for in the return to equity — and hence the weighted average cost of capital — estimated for regulated businesses" and determined a range for gamma of 0.25–0.39, based on a distribution rate of 0.7 and a range for the market value of imputation credits of 0.35–0.55 (ERA, Explanatory Statement for the Rate of Return Guidelines: Meeting the requirements of the National Gas Rules, 16 December 2013, p. 210; ERA, Rate of Return Guidelines: Meeting the requirements of the National Gas Rules, 16 December 2013, pp. 30–31.)

205 AER, Explanatory Statement: Rate of Return Guideline, December 2013, p. 160.

206 AER, Explanatory Statement: Rate of Return Guideline, December 2013, p. 158.

207 As discussed further below, the equity ownership approach only indicates the maximum set of investors eligible to redeem credits, by reference to the proportion of investors that are domestic. Within the set of domestic investors, there are likely to be some that are not eligible to redeem imputation credits, for example due to the 45-day rule.

208 Following the decision in *Energex*, the AER followed the Tribunal's approach to estimating gamma in determinations in both the electricity and gas sectors (except in some electricity transmission determinations, where, under the previous NER, it was bound to adhere to its position in the SORI). Prior to the Tribunal decision in *Energex*, the AER had correctly recognised that gamma should be estimated as the value of imputation credits, but had made some errors (identified by the Tribunal) in estimating that value. For example, in its 2009 WACC Review Final Decision, the AER referred to gamma as representing the 'value for imputation credits', noting that "Standard regulatory practice in Australia is to incorporate a value for imputation credits in determining the appropriate company tax allowance (the 'corporate income tax building block') to include in the required revenues of regulated businesses" (AER, Final Decision: Electricity transmission and distribution network service providers — Review of the weighted average cost of capital (WACC) parameters, May 2009, p. 393).

that the true value of imputation credits is significantly less than their face value.

In formulating this revised approach, the AER considers selective passages from the original Officer (1994) paper.[209] Those passages do not support the approach suggested by the AER. They were concerned with explaining the theory of the effect of imputation credits on the calculation of a rate of return under stylised conditions for the purpose of explanation, including an assumption that there are no foreign investors, or that there is full distribution and maximum utilisation of imputation credits.

The AER then goes on to consider the life cycle of tax cash flows, identifying that tax is either kept by the government or returned to the investor as a credit against personal tax.[210] On page 143 of Annexure H to the Guideline, the AER refers to this cash flow analysis, emphasises that it is concerned with the face value of imputation credits, and then says that the cash flow interpretation of the value of imputation credits is supported by the 2004 paper by Officer and Hathaway. However by referring to only a select passage from Officer and Hathaway (2004), the AER misunderstands and misapplies the findings of this paper, which are to completely the *opposite* effect of the statements in Annexure H to the Guideline.

Importantly, the Officer and Hathaway (2004) paper referred to by the AER observes:[211]

- first, that in the period 1988–2002 approximately $188 billion worth of imputation credits out of total tax collections of $265 billion have been distributed to shareholders, implying a distribution rate of 71%; and
- secondly, that by using dividend drop off studies, it appears that the average *value* of distributed imputation credits is *"about 50% of their face value"*.

Officer and Hathaway (2004) then go on to conclude that the Australia-wide average gamma over the period 1988–2002 was 0.355, based on their estimates of the distribution rate (71%) and the value of distribution imputation credits, as indicated by dividend drop-off analysis (50% of face value).[212] Thus, Officer and Hathaway (2004) clearly characterise gamma as reflecting the *value* of imputation credits, and provide an estimate that is consistent with this characterisation (ie an estimate based on dividend drop-off analysis.

The conclusion of Officer and Hathaway (2004) on this point is clear, when the passage quoted by the AER on page 143 of Annexure H to the Guideline is read in its full context. In context, the relevant passage is as follows:[213]

"… it is quite important to recognise that the value factor of credits (the value of distributed credits) is not in itself the "gamma" factor used within the Officer WACC formulae, a point which is often confused or mis-represented. The gamma factor in the various Officer WACC formulae represents that part of the tax paid by companies as company tax but is in reality a pre-payment of personal tax. Because we typically estimate costs of capital after company tax but before personal tax, the portion of company tax prepayments captured as pre-payment of personal tax (ie gamma) is a cash flow that has to be added to shareholders' pre-personal tax cash flow. ***The Australia-wide average gamma over all companies and over the entire period 1988–2002 is 0.355. That is, of the $265 billion ostensibly collected as company tax, about 50% of the distributed $188 billion, namely $94 billion, is valued in the market place*** *as either being a pre-payment of tax liabilities or, recently for some entities, redeemable as cash. So the effective company tax collection has been about $171 billion.* ***Gamma is not the value of distributed credits alone. It is the compounding of the two factors — the fraction of tax distributed as credits multiplied by the value of distributed credits.*** *[Emphasis added]"*

Thus, when in the passage cited by the AER, Officer and Hathaway state that "it is quite important to recognise that the value factor of credits (the value of distributed credits) is not in itself the "gamma" factor used within the Officer WACC formulae", they do not mean that examining the value of distributed credits is incorrect. Rather, they simply mean that the gamma factor is a *combination* of the distribution rate and the value of those distributed credits to investors.

This misuse of the Officer and Hathaway paper is a serious error in Annexure H to the Guideline.

More generally, the AER's cash flow analysis, and consideration of how much tax is retained by the government, is a complete distraction from the issue that arises under the NER. Corporate income tax is a real cost to the company. It is not merely theoretical. It reduces (usually by 30%) the amount of income available to shareholders (either held in the company or distributed). It therefore reduces the return that otherwise would be available to investors. However, because the payment of this corporate tax may in due course confer a benefit on investors, it is relevant to identify the value and extent of that benefit, because it is a benefit that derives from the payment of corporate income tax by the company and it affects the investor's overall return from the investment. It is *only* the investor's return that is relevant (not the tax earned by the government, or the face *value* of credits). It is the investor's return — ie the value they obtain from their investment, and whether it meets their required return — that governs whether they would choose to invest in the entity. To consider the face value of credits, or whether an investor is eligible to receive credits, does not address the correct issue.

209 AER, Explanatory Statement: Rate of Return Guideline, December 2013, Appendix H, pp. 137–139.
210 AER, Explanatory Statement: Rate of Return Guideline, December 2013, Appendix H, pp. 140–143.
211 Neville Hathaway and Bob Officer, 'The Value of Imputation Tax Credits: Update 2004', November 2004, pp. 4–5.
212 Neville Hathaway and Bob Officer, 'The Value of Imputation Tax Credits: Update 2004', November 2004, p. 8.
213 Neville Hathaway and Bob Officer, 'The Value of Imputation Tax Credits: Update 2004', November 2004, pp. 7–8.

Finally, on page 143 of Annexure H, the AER states that using the full face value of imputation credits is *"consistent with the common assumption that for simplicity, dividends should be assumed to be worth their face value in the Officer framework".* It is a reasonable (albeit simplifying) assumption that a cash dividend paid directly into an investor's bank account is worth the amount of the dividend. However, it is an entirely *unreasonable* assumption to assume that every $1 of imputation credits is worth $1 to investors. As will be discussed below in relation to theta, there are compelling reasons why every $1 of imputation credits are not worth $1 to investors. It cannot be assumed that the value of imputation credits to investors is equal to their face value; rather, the face value of credits represents no more than an upper bound of their true value to investors.

26.4.4 Conclusion on the correct approach to defining gamma

The correct approach under the NER, having regard to the statutory objective, is to determine gamma as the value to equity-holders of imputation credits. This is the interpretation which is specified by the NER, when properly interpreted, and which best promotes the NEO, because it provides for an adjustment to the income tax building block for imputation credits which properly reflects their value to investors.

This approach aligns with:

- the proper role of gamma within the NER building block framework, and the objectives of that framework as embodied in the NEO;
- the approach to estimating other rate of return parameters, which are directed at estimating returns required by investors, rather than the face value of cashflows;
- the treatment of gamma in the financial and economic literature (particularly Officer (1994) and Monkhouse (1997));
- the approach taken by the Tribunal in *Energex*; and
- previous AER practice (both following the decision of the Tribunal in *Energex*, and prior to that decision) and the practice of other regulators.

The analysis of the payout ratio and theta set out below follows this approach.

Payout ratio

Previous AER/Tribunal approach to the payout ratio

In all decisions over the past three years, the AER has adopted a payout ratio of 0.7, based on ATO data on distribution of imputation credits.

The AER's approach to the payout ratio followed the approach taken by the Tribunal in *Energex*. Prior to that decision of the Tribunal, the AER had adopted a value for the distribution rate of 1.0.[214]

However, in the course of the Tribunal proceedings in the *Energex* matter, the AER accepted that there was in fact no evidence to support a distribution rate higher than 0.7.[215] Accordingly, in the Energex matter, and in all decisions of the AER since, a distribution rate of 0.7 has been adopted.

AER position in the Rate of Return Guideline

The AER has proposed to adopt a distribution rate of 0.7 in its Guideline.

Consistent with its previous approach, the AER estimates the distribution rate as a market-wide parameter, using ATO data. The AER refers to ATO data over a 23-year period (from 1987–88 to 2010–11), which indicates a cumulative distribution rate of 0.7.

In its Explanatory Statement, the AER refers to some evidence which suggests that the distribution rate may be rising over time, but says this evidence is currently inconclusive.[216]

Latest evidence on the payout ratio

The most recent evidence on the distribution rate confirms that a value of 0.7 is appropriate. This evidence does not suggest that the payout ratio is increasing over time, as suggested by the AER in its Explanatory Statement.

NERA's recent report on the payout ratio for the ENA concludes that:[217]

- the cumulative payout ratio up until 2010–11 drawn from tax statistics is 0.69; and
- there is no evidence that the payout ratio has increased over time.

The findings of the NERA report are consistent with earlier studies.[218]

Conclusion on the payout ratio

SA Power Networks therefore proposes a payout ratio of 0.7, consistent with the AER's Guideline. SA Power Networks agrees that the best estimate of the payout ratio at the present time is 0.7.

26.4.5 Theta

Previous AER/Tribunal approach to theta

Prior to issuing its Guidelines, the AER had taken an approach to theta which reflected an economically correct interpretation of the role of gamma in the building block framework. In measuring the value of distributed imputation credits, the AER sought to measure their market value, or value to equity-holders, rather than simply their redemption rate.

The AER correctly recognised in its May 2009 Statement of Regulatory Intent on WACC parameters (**SORI**) that the way in which theta is measured ought to reflect the fact that

214 AER, Final Decision: Electricity transmission and distribution network service providers — Review of the weighted average cost of capital (WACC) parameters, May 2009, pp. 420–421.

215 Application by Energex Limited (Distribution Ratio (Gamma)) (No 3) [2010] ACompT 9, [2].

216 AER, Explanatory Statement: Rate of Return Guideline, December 2013, p. 165.

217 NERA, 'The Payout Ratio: A report for the Energy Networks Association', June 2013.

218 For example: Hathaway, N., Officer, R.R., The value of imputation tax credits: update 2004, November 2004, p. 11.

it represents the value of imputation credits to investors. As such, the AER gave real weight to market value studies in estimating theta. Further, the AER correctly observed that tax statistics could provide no more than an upper bound for theta, since there were various factors which may reduce the value of credits to investors (below face value), including risk of investment and the time value of money.[219]

In the SORI, the AER determined a value for theta of 0.65. This value represented approximately the midpoint between its estimate of the market value of imputation credits (0.57) and its 'upper bound' value from tax statistics (0.74). This value was subsequently applied in a number of AER decisions, including for ETSA Utilities (now SA Power Networks), Energex, Ergon and Jemena Gas Networks.

In its review of the AER's determinations for ETSA Utilities, Energex and Ergon, the Tribunal maintained the AER's approach of seeking to establish a market value for imputation credits. However, the Tribunal identified a number of deficiencies in the AER's approach to measuring market value, including:

- given that the AER had identified tax statistics as providing an upper bound for theta only, it was illogical to average the estimate from tax statistics with the point estimate of market value from dividend drop-off analysis. The Tribunal stated that tax statistics could provide no more than a check on an estimate of theta (ie to check that the estimate is not too high);[220] and
- there were deficiencies in the dividend drop-off analysis that had been relied on by the AER.

In order to resolve these issues, the Tribunal:

- sought a state-of-the-art dividend drop-off study, to provide an estimate of the market value for imputation credits;
- found that the SFG Consulting (2011) study provided the best available estimate of market value; and
- set a value for theta of 0.35, based on the results of the SFG Consulting (2011) study.[221]

The position of the Tribunal has been adopted by the AER in subsequent determinations in both the electricity and gas sectors (except in some electricity transmission determinations, where, under the previous NER, it was bound to adhere to its position in the SORI).

The position of the Tribunal has also been adopted by other regulators, including the ERA and IPART.[222]

AER position in the Guideline

As discussed above, the AER takes a very different approach to estimating theta in the Explanatory Statement to its Guideline, and by implication in specifying a value for gamma in the Guideline itself. Rather than seeking to estimate the value of distributed imputation credits, the AER instead seeks to estimate what it refers to as *"the before-personal-tax reduction in company tax per one dollar of imputation credits that the representative investor receives".*[223] Elsewhere in the Explanatory Statement, the AER refers to its conceptual definition of theta as *"the expected ability of equity holders to use the imputation credits they receive to reduce their personal tax".*[224]

The AER says that it has estimated theta (in accordance with its definition) based on the body of utilisation rate estimates, having regard to its strengths and weaknesses.

The AER considers that the relevant body of utilisation rate estimates includes the following:

- ***The equity ownership approach***, which suggests an estimate of theta between 0.7 and 0.8. This approach involves estimating the value weighted proportion of eligible investors (ie those eligible to redeem imputation credits) out of all investors in the Australian market. The AER states that this approach provides a "conceptually sound" estimate of the representative investor's expected utilisation rate, in the sense that it aligns with the AER's conceptual definition of theta.
- ***Tax statistics estimates***, which suggest an estimate of between 0.4 and 0.8. The AER says that these estimates report "the actual dollar benefit to Australian taxpayers from their imputation credits".[225] It is said that tax statistics estimates align closely with the AER's conceptual definition of the utilisation rate, albeit with some slight differences due to differences between the set of investors who actually redeem credits and the set of eligible equity holders. The AER notes reported problems with data quality and consistency.[226]
- ***Implied market value estimates*** (including from dividend drop-off studies) which suggest an estimate between 0 and 0.5. However, the AER says that these studies do not align with the AER's conceptual definition of the utilisation rate, as well as suffering from interpretation problems (eg the AER states that the results of these studies are sensitive to methodological and data choices, and that there is no consensus on all aspects of the methodology).[227] The AER says that is has "somewhat less regard to this approach".[228]
- ***The conceptual goalposts approach*** which suggests an estimate between 0.8 and 1. This approach involves estimating a utilisation rate range which would generate a 'reasonable return on equity' in the majority of scenarios between full capital segmentation and full integration.[229]

The AER concludes, based on the above evidence, that a

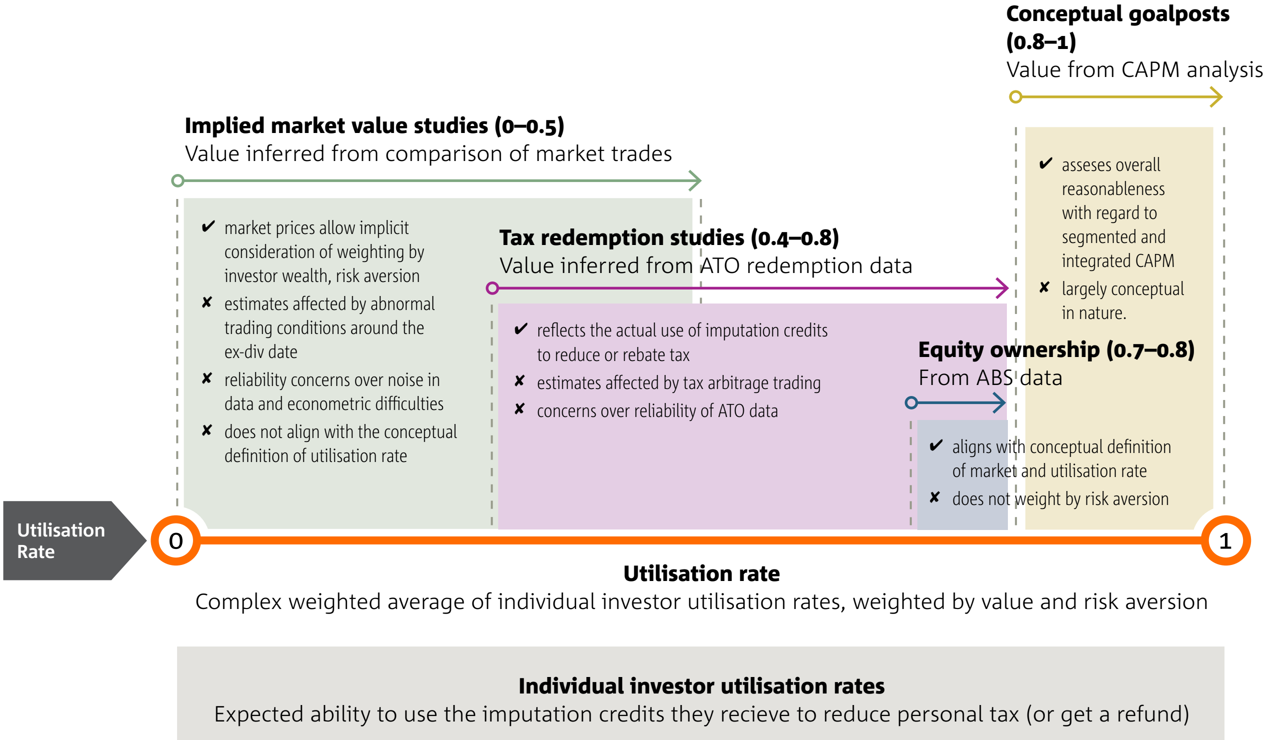
219 AER, Final Decision: Electricity transmission and distribution network service providers — Review of the weighted average cost of capital (WACC) parameters, May 2009, pp. 455–456.
220 Application by Energex Limited (No 2) [2010] ACompT 7, [91]-[92].
221 Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9.
222 IPART, Review of imputation credits (gamma): Research — final decision, March 2012; ERA, Rate of Return Guidelines: Meeting the requirements of the National Gas Rules, 16 December 2013, pp. 30–31. As noted above, the ERA has determined a range for gamma of 0.25–0.39, based on a distribution rate of 0.7 and a range for the market value of imputation credits of 0.35–0.55.

223 AER, Explanatory Statement: Rate of Return Guideline, December 2013, p. 165.
224 AER, Explanatory Statement: Rate of Return Guideline, December 2013, p. 174.
225 AER, Explanatory Statement: Rate of Return Guideline, December 2013, p. 174.
226 AER, Explanatory Statement: Rate of Return Guideline, December 2013, p. 159.
227 AER, Explanatory Statement: Rate of Return Guideline, December 2013, pp. 176–177.
228 AER, Explanatory Statement: Rate of Return Guideline, December 2013, p. 159.
229 This approach is based on theoretical research undertaken by Associate Professor Lally, which indicates that a value for theta of 1 is implied by the assumptions underpinning the CAPM (ie fully segmented capital markets). The AER extends this analysis to determine a range for theta which would generate a 'reasonable return on equity' in the majority of scenarios between full capital segmentation and full integration.

reasonable estimate of theta is 0.7. The AER does not state precisely how it has weighted each piece of evidence other than stating that it has "somewhat less regard" to implied market value studies. Indeed, it is apparent that little or no weight is given to implied market value estimates, given that the AER's theta estimates falls well outside the range indicated by market value studies. It seems that the AER has almost entirely relied upon the equity ownership approach and tax statistics estimates, reflecting its view that these two methods best reflect its conceptual definition of theta.

The AER's view of the relevant evidence, and their conclusion on theta, is summarised in Figure 26.2 below (Figure 9.1 from the Explanatory Statement).

Figure 26.2: AER view of relevant evidence on theta



SOURCE AER, EXPLANATORY STATEMENT: RATE OF RETURN GUIDELINE, DECEMBER 2013

The AER acknowledges its altered approach in the Explanatory Statement to its Guideline, stating:[230]

"We acknowledge that we have previously rejected this conceptual framework in favour of a market value framework, similar to that espoused by the ENA and APIA. However, our explanatory statement set out how we had systematically re-evaluated the entire body of evidence on gamma, and why we now reached a different conclusion on the appropriate conceptual framework."

Under the AER's new conceptual approach, theta is defined as *"the extent to which investors can use the imputation credits they receive to reduce their personal tax"*.[231] In effect, the AER is simply seeking to estimate the proportion of distributed credits which can be redeemed. The AER is not seeking to estimate the proportion that are in fact redeemed, or (more importantly) the value of redeemed credits to investors.

SA Power Networks considers that this re-interpretation of theta cannot be supported in light of the statutory objective and context for including gamma in the building block framework. For the reasons set out above, theta must be estimated as the value of distributed imputation credits to equity-holders. This is the conventional and orthodox approach to estimating theta. It is also the approach which best gives effect to the NEO, as it provides for recognition of the value to equity-holders of imputation credits and provides for overall returns which promote efficient investment.

SA Power Networks is not aware of any economic theory or expert views which support the AER's novel and unorthodox approach to interpreting theta. Economic experts generally agree that theta should be a measure of the value of imputation credits, not the extent to which they can be redeemed.

230 AER, Explanatory Statement: Rate of Return Guideline, December 2013, Appendix H, pp. 148–149.
231 AER, Explanatory Statement: Rate of Return Guideline, December 2013, p. 159.

In the accompanying expert report, Professor Stephen Gray explains the theoretical basis for defining theta as the value of imputation credits to investors. Professor Gray also notes that the AER is alone in its conceptual definition of theta, and that none of the experts cited by the AER support its position.[232]

Correct approach to estimating theta

The approach to estimating theta must reflect what this parameter is seeking to measure — the value that is placed on those imputation credits if they are utilised.

Evidence relevant to determining the value of imputation credits

Only one of the sources of evidence referred to by the AER in its Guideline — implied market value estimates — provide a point estimate of the value of distributed imputation credits. Market value studies, and particularly dividend drop-off studies, measure the value of imputation credits to equity-holders, as reflected in stock prices.

None of the other sources of evidence referred to by the AER provide a point estimate for the value of imputation credits, although some may indicate the upper bound for this value.

Role of utilisation/redemption data

Utilisation rates (if measureable) may, at best, provide an indication of the upper bound for value of distributed credits. Clearly the value of distributed credits can be no more than the total face value of those credits that are redeemed by investors. However the value of imputation credits to equity holders may be significantly less than the face value of those that are redeemed, and as such the rate of redemption cannot be assumed to represent the value of credits redeemed. As set out below, the measures of utilisation rates used by the AER are not accurate or reliable. Further, a key piece of evidence relied upon by the AER to derive a utilisation rate is not a measure of utilisation at all.

The equity ownership approach is above any upper bound because not all imputation credits distributed to Australian investors are able to be utilised (for example, because of the 45 day rule[233]), and a smaller percentage still are actually utilised. The equity ownership approach is therefore not a proper measure of theta, and this is so even on the AER's revised approach.

Reasons for theta being less than the full face value of distributed credits

There are several reasons why the value of credits may be expected to be lower than rates of redemption or potential for redemption. A number of these reasons were identified by Professors McKenzie and Partington, in a March 2011 report to the AER which is referred to in the Explanatory Statement. They are also explained in detail in the accompanying expert report of Professor Stephen Gray.

232 SFG Consulting, 'An appropriate regulatory estimate of gamma', May 2014, Appendix 5.

233 The effect of the 45-day rule is acknowledged by the AER in its Rate of Return Guideline Explanatory Statement (AER, Explanatory Statement: Rate of Return Guideline, December 2013, Appendix H, p. 137). It has also been noted by the AER's consultants, Professors McKenzie and Partington (Michael McKenzie and Graham Partington, Report to the AER: Response to questions related to the estimation and theory of theta, March 2011, p. 16).

They include:[234]

- **45-day rule.** Since 2000, Australian tax rules have prevented investors from redeeming imputation credits where they hold shares for only a short period of time around the ex-dividend day. The 45-day rule (or 'holding period rule') requires traders to hold a share for at least 45 days around the ex-dividend day in order to gain entitlement to the imputation credit. Beggs and Skeels (2006) note that the introduction of this rule (along with other changes introduced round the same time) reduced the capacity of important classes of investors to use imputation credits.[235] It has been estimated that the 45-day rule has about a 5–10% impact on the redemption rate.[236]
- **Transactions costs.** Transactions costs associated with redemption of credits may include requirements to keep records and follow administrative processes. This can be contrasted with realisation of cash dividends, which are paid directly into bank accounts. The transactions costs associated with redemption of imputation credits will tend to reduce their value to investors, and dissuade them from redemption;
- **Time value of money.** There will typically be a significant delay (which can be years) between credit distribution and the investor obtaining a tax credit. This may be a period of several years in some cases, for example where credits are distributed through other companies or trusts, or where the ultimate investor is initially in a tax loss position. Over this period, the value of the imputation credit to the investor may be expected to diminish, due to the time value of money; and
- **Portfolio effects.** Portfolio effects refer to the impact of shifting the investor's portfolio away from the optimal construction (including overseas investments) in order to take advantage of imputation. An investor who would otherwise invest overseas (to get a better return from the overall portfolio) might choose instead to make that investment in Australia to obtain the benefit of an imputation credit. This reallocation of portfolio investment would tend to continue with the relevant credit having less and less marginal value until an equilibrium is reached with the credit having no additional value: that is, on average, the value of the imputation credits will be less than the face value. To the extent that an investor reduces the value of their overall portfolio simply to increase the extent to which they can redeem imputation credits, this lost value will be reflected in a lower valuation of the imputation credits. These portfolio effects are further explained in the accompanying expert report of Professor Stephen Gray.[237]

234 SFG Consulting, An appropriate regulatory estimate of gamma, May 2014, [65]-[70]; Michael McKenzie and Graham Partington, Report to the AER: Response to questions related to the estimation and theory of theta, March 2011, pp 3–5; David J Beggs and Christopher L Skeels, 'Market Arbitrage of Cash Dividends and Franking Credits, *The Economic Record*, Vol 82, No 258, September 2006, pp. 239–252.

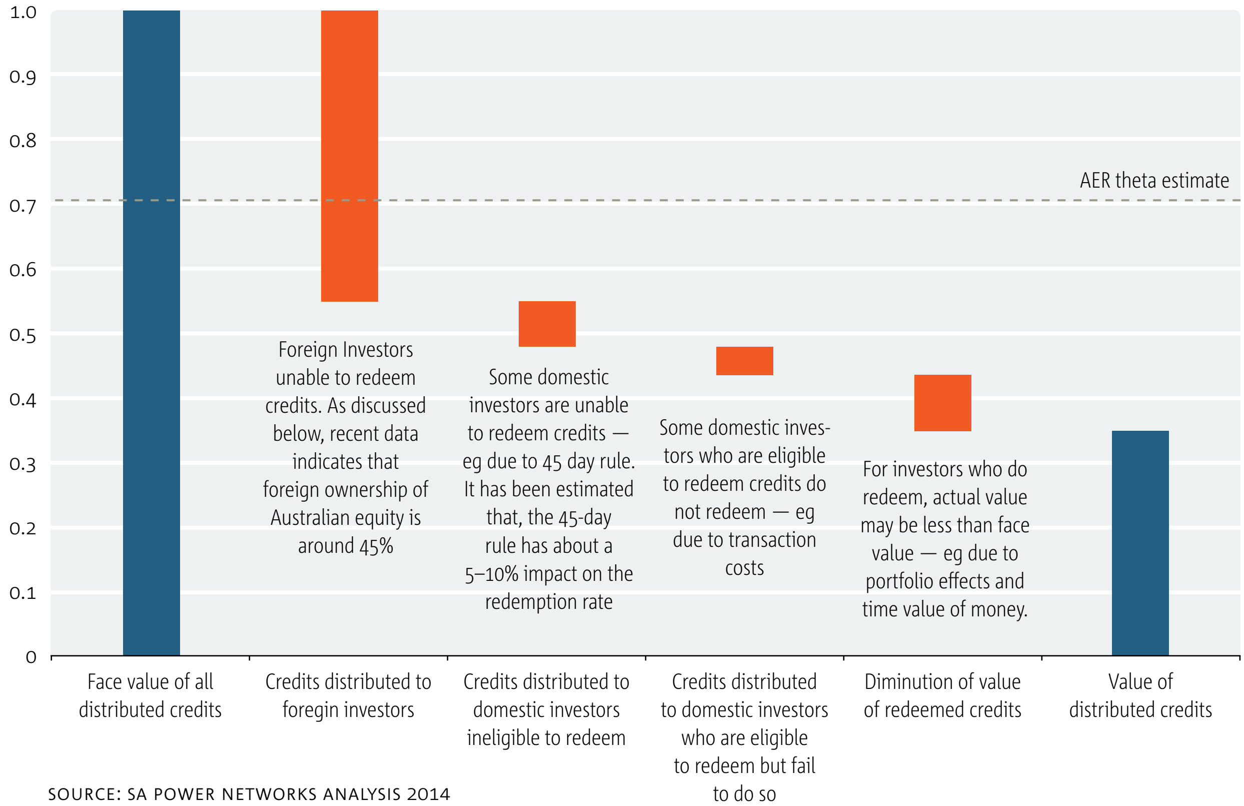
235 David J Beggs and Christopher L Skeels, 'Market Arbitrage of Cash Dividends and Franking Credits', *The Economic Record*, Vol 82, No 258, September 2006, pp. 239–252, p. 251.

236 John C Handley, 'Further issues relating to the estimation of gamma', Report prepared for the Australian Energy Regulator, 26 October 2010, p 31, footnote 59.

237 SFG Consulting, 'An appropriate regulatory estimate of gamma', May 2014

The impact of each of the above factors is illustrated in Figure 26.3 below. While the estimated impacts are illustrative only, they are based on available information on the likely impact of each factor where indicated. The actual impact of each factor may potentially be greater than is indicated in the chart, implying a lower value for theta.

Figure 26.3: Illustrative impact on value of imputation credits



SOURCE: SA POWER NETWORKS ANALYSIS 2014

The fact that market value estimates of theta are consistently significantly lower than the face value of distributed credits is consistent with the powerful reasons why actual value is less than face value and indicates that these factors do indeed have a bearing on the value of credits.

Problems with measuring utilisation rates

Even if utilisation/redemption rates were seen as relevant to determining a point estimate of theta, the very significant unresolved problems identified with the tax data would mean that no weight could be placed on the utilisation rates that are estimated using this data. In a recent report for the ENA, Dr Neville Hathaway identifies very significant unexplained discrepancies in the ATO data used to estimate utilisation rates, including:[238]

- whereas the ATO franking account balance data indicates net credit distribution over the period 2004–2011 of $292.2 billion, the ATO company dividend data indicates much lower net credit distribution over this period, of approximately $204.7 billion; and
- due to this large discrepancy, very different estimates of the credit utilisation rates may be derived from the ATO data, depending on whether the franking account balance data or the company dividend data is used to estimate the quantum of credits distributed — if the company dividend data is used then the utilisation rate is 62.3% over the period 2004–2011, but if franking account balance data is used, the utilisation rate falls to 43.7%.

The very significant discrepancies identified by Dr Hathaway remain unexplained, despite queries being lodged with the ATO. In light of these unexplained discrepancies, Dr Hathaway concludes that the ATO statistics cannot be relied upon for making conclusions about the utilisation of franking credits.[239] The AER's expert, Associate Professor Lally, likewise has stated that *"the best that can be said about all this is that the redemption rate is uncertain".*[240]

238 Dr Neville Hathaway, 'Imputation Credit Redemption ATO data 1988–2011: Where have all the credits gone?', September 2013, p. 6.

239 Dr Neville Hathaway, 'Imputation Credit Redemption ATO data 1988–2011: Where have all the credits gone?', September 2013, p. 5. It should be noted however that while the data in relation to utilisation appears unreliable, the ATO data on distribution of credits is reliable, and produces stable estimates of the distribution rate over time.

240 Lally, 'Estimating Gamma', 25 November 2013, p. 15

The AER uses three estimates for utilisation rates: 0.44, 0.62 and 0.81, which it rounds to range of 0.4–0.8.[241] The upper end of this range is derived from the Handley and Maheswaran (2008) utilisation rate study. However, the relevant figure from Handley and Maheswaran utilised by the AER is not the product of a review of taxation statistics or any other data on utilisation rate. For the period 2001–2004 (the period for which the AER relies with respect to this study), no empirical estimate of the actual utilisation rate is provided. Rather, Handley and Maheswaran simply make an assumption that all credits received by individuals and funds will be used.[242] The authors note, at 86–87, that for resident individuals and resident funds they have **assumed** zero Excess Credits (ie 100% usage of credits received) for the years 2001–2004, "consistent with investor rationality". This is reflected in Table 4, where the utilisation rate for resident individuals and resident funds is set to 1.00 for each of the years 2001–2004. It is not a measurement at all, but an assumption. The reason that the figure is 0.81 rather than 1 is only because the assumption is then weighted between domestic and foreign investors. Accordingly, this study <u>cannot be relied upon</u> to provide information on the actual utilisation rate in the post-2000 period and should be disregarded by the AER. That means that the AER's range for utilisation rates of 0.4–0.8 cannot be supported, and could only be approximately 0.4–0.6, or more accurately 0.44–0.62.

The only available empirical evidence on the actual utilisation rate in the post-2000 period is Dr Hathaway's study, which indicates a utilisation rate of 44% or 62% over the period 2004–2011, depending on which ATO data is used. However, given Dr Hathaway's very strong reservations regarding the reliability of this data (in which he cautions against anyone relying on those parts of his earlier reports which focused on ATO statistics), we would submit that these estimates should be disregarded.

Measuring equity ownership

In relation to the equity ownership rates referred to by the AER, there are two important points worth noting.

The first is that rates of domestic ownership in Australian entities are in fact lower than what is stated by the AER. Professor Gray analyses this issue in his report. The figure of 70% used by the AER is drawn from an ABS figure from 2007. However, the ABS data suggests that both before and since, the percentage of Australian ownership is lower (and the percentage of foreign ownership commensurately higher). Further the 2007 statistics referred to by the AER include equity in entities that are not relevant for this purpose, such as the central bank.[243]

Based on the most recent ABS data, Professor Gray estimates that the percentage of foreign ownership is now around 45%.[244] This is confirmed by a recent (2013) estimate from the ASX, which indicates that foreign ownership now stands at 46%.[245] A Reserve Bank study in 2010 recorded the increase in foreign ownership after 2007, brought about by a number of matters including very significant capital raisings in 2008 and 2009 as a result of the GFC.[246]

The second point to note is that these domestic equity ownership rates do no more than indicate a figure that must be higher than theta, given the various reasons why domestic investors cannot and do not fully utilise imputation credits (rules preventing some investors from redeeming, transaction costs, and so forth), not to mention reasons why investors do not fully value credits.

As noted, the figure for equity ownership (approximately 55%) is no more than an upper bound for theta. This implies that theta must be less than 0.55.

Role of the AER's 'conceptual goalposts' approach

SA Power Networks considers that the 'conceptual goalposts approach' provides no relevant information on the market value of imputation credits.

The AER's derivation of its 'conceptual goalposts' is not fully explained in the Explanatory Statement to its Guideline. While the conceptual framework for this approach appears to originate from Associate Professor Lally[247], the AER states in its Explanatory Statement that it has undertaken further analysis using the Lally framework, in order to refine the estimates.[248] The AER says that this further analysis indicates that the relevant goalposts for theta are 0.8 and 1.0, meaning that on the AER's analysis, a utilisation rate between these two values *"will generate a reasonable return on equity … in the majority of permutation scenarios"*.[249] It is not explained how the AER has determined its goalposts, nor is it clear what is deemed to be a 'reasonable' return on equity in this context, or what is meant by a 'majority' of permutation scenarios (ie whether this is just a bare majority, or most scenarios).

SA Power Networks has a number of concerns with the way in which the Lally conceptual framework has been used by the AER to determine 'goalposts' for theta, including:

- at a general level, this approach requires assumptions to be made about the required return on equity in a range of hypothetical scenarios. As these hypothetical scenarios do not reflect reality, the assumptions about required returns on equity can have no basis in empirical evidence;

241 AER, Explanatory Statement: Rate of Return Guideline, December 2013, p. 175.
242 John C Handley and Krishnan Maheswaran, 'A Measure of the Efficacy of the Australian Imputation Tax System', The Economic Record, Vol 84, No 264, March 2008, pp. 82–94.
243 ABS, Feature Article: 'Foreign Ownership of Equity', September 2007.
244 SFG Consulting, 'An appropriate regulatory estimate of gamma', May 2014, Appendix 8.
245 ASX, 'Australian Cash Equity Market', 2013. Available at: http://www.asx.com.au/documents/resources/australian_cash_equity_market.pdf (accessed 8 May 2014).
246 Black and Kirkwood, 'Ownership of Australian Equities and Corporate Bonds', RBA Bulletin, September Quarter 2010.
247 Lally, 'Estimation of gamma', November 2013, pp. 38–47.
248 AER, Explanatory Statement: Rate of Return Guideline, December 2013, p. 181.
249 AER, Explanatory Statement: Rate of Return Guideline, December 2013, p. 181.

- certain assumptions made by Associate Professor Lally about the required return on equity in certain scenarios are highly debateable at best. In particular, the assumption that the risk-free rate would be the same in the full segmentation and full integration scenarios would seem implausible, given that yields on government bonds will almost certainly be affected by demand from foreign investors;
- the values for theta in each of the scenarios appear to be based on an assumption that imputation credits are fully valued by all investors who receive credits and are eligible to redeem them — this is the only way in which a theta value of 1.0 could be derived in the 'full segmentation' scenario. For the reasons set out above, this assumption is inconsistent with practical and empirical reality.

In any event, neither of the theoretical goalpost values identified by the AER provide any relevant information as to the actual value of theta for investors in the AER's defined market (being the Australian domestic market, recognising the presence of foreign investors to the extent that they invest in the Australian market[250]).

Both values are derived based on extreme theoretical assumptions about the investor population. Neither value reflects the actual value of imputation credits to the relevant investor population.

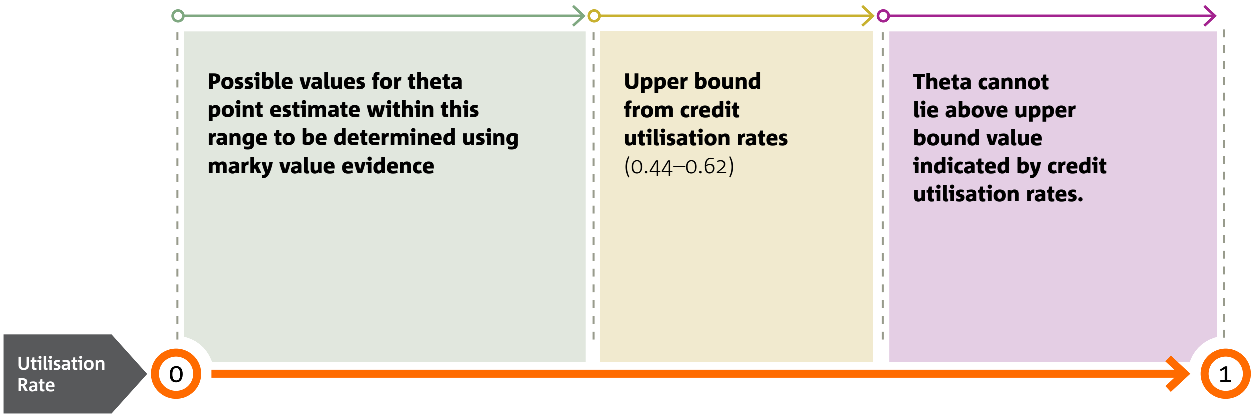
Conclusion — the correct approach to estimating theta
For the reasons set out above, SA Power Networks considers that the only source of evidence that can be used to derive a point estimate of theta is market value evidence. This is the only available form of evidence which is capable of indicating the actual value of imputation credits to investors.

Further, for the reasons set out above, the market value evidence produces a figure for theta which is plausible and reasonable having regard to the reasons why credits are not fully utilised or fully valued.

To the extent that evidence of utilisation or redemption rates is to be used, this can only be used to indicate the upper bound for theta. In other words, utilisation/redemption rates can only be used to confirm that estimates from market value evidence are not too high.

This approach is depicted in Figure 26.4 below.

Figure 26.4: Approach to determining theta



Current market value evidence
Market value studies provide evidence of the value placed on imputation credits by investors, as reflected in the price they are willing to pay for shares.

Methods for measuring market value
The most common form of market value study is the dividend drop-off study. This type of study estimates investors' valuation of dividends and imputation credits, by reference to the change in willingness to pay for shares when dividends are distributed.

There are potentially other methods of estimating investors' valuation of imputation credits. For example, analysis of pricing of derivative instruments, such as futures contracts, can be used to infer a value for dividends and imputation credits.[251] Alternatively, if there was a market for the trading of imputation credits, a market price could be observed.

However these alternative methods are not as well developed as the dividend drop-off measurement method. In the case of the market price observation method, this is largely because Australian tax laws now prevent the trading

250 In the Rate of Return Guideline Explanatory Statement, the AER states that, consistent with the 2009 WACC review, it proposes to define the market as the Australian domestic market, recognising the presence of foreign investors to the extent that they invest in the Australian market (AER, Explanatory Statement: Rate of Return Guideline, December 2013, p. 161).

251 These studies are based on a hypothesis that the difference between the futures prices and the cash price of an individual stock or stock-index at any point in time will be a function of the financing cost, and the value of dividends and franking credits over the period to maturity. This hypothesis, and econometric techniques used to derive estimates of theta based on this hypothesis, are explained in detail in: Cannavan, Finn and Gray (2004), ' The value of dividend imputation tax credits in Australia', 73 Journal of Financial Economics, p. 167.

of franking credits, meaning that a market price cannot be observed.[252] Some of these alternative methods are discussed briefly below.

SA Power Networks considers that the best available method for estimating the value of imputation credits to investors is the dividend drop-off method, and we therefore give primary weight to this method in determining a value for theta.

Relevant dividend drop-off studies

The AER identifies a number of recent dividend drop-off studies in its Explanatory Statement. These studies cover various time periods and each use different methodologies.

SA Power Networks considers that not all dividend drop-off studies should be given equal weight, given the differences in methodology, data and time periods covered. Rather, the most relevant dividend drop-off study or studies need to be identified, having regard to the strengths and weaknesses of each one. In particular, the choice of relevant study (or studies) must take into account:

- the time period covered by each study, and the extent to which investors' valuation of credits during that time period is likely to be reflective of current valuations; and
- the robustness of the methodology and data relied on.

In relation to time period, SA Power Networks considers that only studies covering the post-2000 period can be taken into account. Significant changes to Australian tax laws came into effect on 1 July 2000, which almost certainly caused a structural break in the way investors valued imputation credits. This has previously been recognised by the AER, causing the AER to (correctly) give no weight to pre-2000 estimates.[253]

There are five dividend drop-off studies covering the post-2000 period, which are identified in Table 26. 2 below. Of these five studies:

- those which use the most robust methodology and data are the two SFG Consulting studies.[254] The first of these studies was undertaken at the request of the Tribunal in the *Energex* matter, and its methodology was specifically designed to overcoming shortcomings in previous studies (including the Beggs and Skeels (2006) study);
- the Beggs and Skeels (2006) study has very significant methodological shortcomings, many of which were identified by the Tribunal in the *Energex* matter.[255] As noted above, the first of the SFG Consulting studies was designed specifically to overcome shortcomings in the Beggs and Skeels (2006) methodology;
- the Vo et al (2013) study uses a similar methodology to the SFG Consulting studies, except that it also reports results with the standard market adjustment removed.[256] The results without this adjustment will be biased due to exogenous factors which may be driving the broader market over the ex-dividend day, and according should be given no weight. The results produced by Vo et al with the market adjustment are precisely in line with the results of the SFG Consulting studies; and
- the Minney (2010) study produces similar results to the SFG Consulting and Vo et al (2013) studies.[257] The slightly higher estimate of theta from this study (0.39, compared to 0.35 estimated by SFG Consulting and Vo et al) can be explained by the constraining assumption that cash is fully valued. Further, the author recommends that the results be interpreted with caution, due to large standard errors associated with the estimates of franking credit values.

252 In July 1997, the Federal Government introduced a package of amendments aimed at preventing short-term trading in dividends and associated imputation credits. Since then, there has been no market for franking credits in which a value can be observed.

253 AER, Final Decision: Electricity transmission and distribution network service providers — Review of the weighted average cost of capital (WACC) parameters, May 2009, pp. 428–430. Associate Professor Lally also appears to recognise that studies based on pre-2000 data should be given limited weight, saying results of these studies "are of much less interest as estimates of the current value of [theta]" (Lally, Estimation of gamma, November 2013, p. 22).

254 SFG Consulting, 'Updated estimate of theta for the ENA', June 2013; SFG Consulting, 'Dividend drop-off estimate of theta, Final report, Re: Application by Energex Limited (No 2) [2010] ACompT 7', 21 March 2011.

255 D. Beggs and C. Skeels, 'Market arbitrage of cash dividends and franking credits', The Economic Record, vol. 82, 2006, pp. 239–252.

256 D. Vo, B. Gellard and S. Mero, 'Estimating the market value of franking credits: Empirical evidence from Australia', ERA working paper, April 2013.

257 A. Minney, 'The valuation of franking credits to investors', JASSA: The FINSA journal of applied finance, vol. 3, 2010, pp. 29–34.

Table 26.8: Dividend drop-off studies covering the post-2000 period

Author(s)	Theta estimate	Notes
SFG Consulting (2013)	0.35	Methodology replicates SFG Consulting (2011) (see below). Dataset extended to cover 2001–2012.
Vo et al (2013)	0.35–0.55 (But correctly 0.35)	Methodology similar to SFG Consulting (2011) and SFG Consulting (2013). However, additional methodological permutations are run, including to exclude the standard market adjustment. As noted by SFG Consulting, the standard approach in dividend drop-off studies is to assume that, but for the dividend, the stock price would have followed the movement in the broad market over the ex-dividend day.* That is, if the broad market index increases by 2% over the ex-dividend day, it is assumed that, but for the dividend, the particular stock would also have increased by 2%. An adjustment is therefore made in most dividend drop-off studies to remove the effect of movements in the broader market. Vo et al (2013) report results both with the standard market adjustment, and without it. The results without this adjustment will be biased due to exogenous factors which may be driving the broader market over the ex-dividend day, and accordingly should be given no weight. The results produced by this study with the market adjustment are precisely in line with the results of the SFG Consulting studies.
SFG Consulting (2011)	0.35	Undertaken at the request of the Tribunal in the *Energex* matter, with a methodology designed to overcome shortcomings in previous studies (including the Beggs and Skeels (2006) study). In particular, the functional form was designed to overcome issues of multicollinearity and the dataset was compiled with a view to eliminating erroneous and outlying observations. Accordingly, the results of this study should be given precedence over earlier studies such as Beggs and Skeels (2006). Point estimate reflects the authors' view as to what is the most stable and robust function form (referred to as 'Model 4'). This is a yield model accounting for heteroskedasticity through a weighting variable that accounts for stock volatility (inverse stock return variance). Using this model produces an average theta estimate of 0.35. The results produced by this model specification are supported by the results of other specifications.
Minney (2010)	0.39	The author of this study recommends that his results should be interpreted with caution, due to large standard errors associated with the estimates of franking credit values. One reason for the large standard errors and slightly higher estimate of theta compared to the SFG Consulting studies may be the constraining assumption that cash is fully valued. This constraint is not imposed in the SFG Consulting or Vo et al studies.
Beggs and Skeels (2006)	0.57	Significant shortcomings in the methodology used in this study were identified by the Tribunal in the *Energex* matter. As noted above, the first of the SFG Consulting studies was designed specifically to overcome these shortcomings. The most significant limitation of this study relates to the functional form used for the regression analysis, which gives rise to multicollinearity issues. Moreover, the methodology and data used for this study could not be subject to the same level of scrutiny as the SFG Consulting and Vo et al (2013) studies, because the underlying data, code and filters are not available for review. Clearly, this study is also not as recent, and relies on an older and more limited dataset. Whereas the SFG Consulting (2013) study uses data up to 2012, this study only covers the period up to 2004.

* SFG Consulting, 'An appropriate regulatory estimate of gamma', May 2014, pp. [138]-[139].

SA Power Networks therefore considers that the best estimate of the value of imputation credits, as reflected in share prices, is 0.35. This is the value for theta recommended in the expert report of Professor Stephen Gray.[258]

The proposed value for theta is based on the results of the most recent and robust dividend drop-off analysis (the SFG Consulting (2013) and SFG Consulting (2011) studies). The same result is produced by the Vo et al (2013) study when the standard market adjustment is applied.

258 SFG Consulting, 'An appropriate regulatory estimate of gamma', May 2014, p. [220].

For the reasons set out above, SA Power Networks considers that the Beggs and Skeels (2006) and Minney (2010) studies should not be given any weight.

The SFG Consulting methodology, which is largely replicated by Vo et al (2013) has been carefully reviewed and amended where necessary to address concerns expressed by the AER and its consultants. Each of the concerns that have been raised by the AER and its consultants in relation to this methodology has been thoroughly addressed. SFG Consulting's response to each of these concerns is set out in detail in its report, and summarised in Table 26.9.

Table 26.9: SFG Consulting's responses to methodological issues raised by the AER and its consultants[259]

AER issue	SFG Consulting's response
Increased or abnormal levels of trading around ex-dividend day may potentially affect empirical estimates.	SFG Consulting notes that to the extent this effect is material, it results in the dividend drop-off (and therefore the theta estimate) being higher than it otherwise would be. This is because the increase in trading around ex-dividend day is driven by a subset of investors who trade shares to capture the dividend and imputation credit and who are therefore likely to value imputation credits highly (ie higher than the average investor). These investors tend to buy shares shortly before payout of dividends (which pushes up the share price) and tend to sell shortly after (which pushes down the share price), the overall effect of which is to increase the size of the price drop-off.
Stability of estimates.	While the estimates produced by Vo et al exhibit some instability, SFG Consulting's estimates are highly stable and robust to the removal of influential observations.
Allocation of value as between cash and imputation credits.	This issue is addressed in the expert report of Professor Stephen Gray.* As noted by Professor Gray, empirical evidence provides a very clear and consistent view of the combined value of cash and imputation credits — this evidence indicates that the combined value is one dollar. The relevant evidence includes the studies by SFG Consulting (2011 and 2013) and Vo et al (2013) referred to above. Allocation can be made based on this clear evidence as to combined value of the cash/credit package.

* SFG Consulting, 'An appropriate regulatory estimate of gamma', May 2014, pp. [158]-[163].

Other market value evidence
As noted in the AER's Guideline, some other forms of market value evidence are also available. These include:
- futures pricing studies, the most recent of which (conducted by SFG Consulting) indicates a value for theta of 0.12; and
- simultaneous trade studies, of which there are none covering the post-2000 period.

SA Power Networks considers that these alternative methods are not as well developed as the dividend drop-off study method. The data and methodology used in these studies has not been subject to nearly the same level of scrutiny and refinement as the data and methodology used in recent dividend drop-off studies (particularly the SFG Consulting studies). Further, many of these studies do not cover the post-2000 period.

Accordingly, while these studies may provide some indication as to the reasonableness of estimates from dividend-drop off studies, SA Power Networks considers that at this stage they cannot be given any significant weight in determining a value for theta.

As noted by the AER, these studies indicate a range of values for theta, between 0 and 0.5.[260] Thus, the range produced by these studies broadly supports the theta value indicated by the SFG dividend drop-off studies.

Conclusion on theta
SA Power Networks proposes a value for theta of 0.35.

Attached are expert reports, listed in the below Table 26.10, prepared for the Energy Networks Association as part of the Guideline consultation process that explain and substantiate SA Power Networks reasoning for proposing a different value for gamma to that in the Guideline:

Table 26.10: AER Rate of Return Guideline: Gamma reports submitted by the Energy Networks Association

Number	Gamma reports
1	NERA Economic Consulting, 'The payout ratio', June 2013
2	SFG Consulting, 'Updated dividend drop-off estimate of theta', June 2013
3	NERA Economic Consulting, 'Imputation credits and equity prices and returns', October 2013
4	SFG Consulting, 'Using market data to estimate the equilibrium value of distributed imputation tax credits', October 2013
5	Hathaway Capital Research, 'Imputation credit redemption ATO data 1988–2011, Where have all the credits gone?', October 2013

259 SFG Consulting, 'An appropriate regulatory estimate of gamma', May 2014, pp. [149]-[170].
260 AER, Explanatory Statement: Rate of Return Guideline, December 2013, Appendix H, pp. 173–174.

The reasons why SA Power Networks is proposing a different value for theta to that in the Guideline include:

- SA Power Networks does not agree with the conceptual framework adopted by the AER for estimating theta, and in particular the focus on utilisation evidence, rather than market value evidence;
- Theta must be estimated as the *value* of distributed imputation credits to equity-holders. This is the conventional and orthodox approach to estimating theta. It is also the approach which best gives effect to the NEO, as it provides for recognition of the value to equity-holders of imputation credits and provides for overall returns which promote efficient investment;
- SA Power Networks considers that the only source of evidence capable of providing a point estimate for the value of distributed imputation credits to investors is market value studies. Evidence of utilisation rates (or potential utilisation rates, as indicated by the equity ownership approach) can only indicate the upper bound for investors' valuation of imputation credits. The conceptual goalposts approach provides no relevant information on the actual value of credits; and
- The best estimate of investors' valuation of imputation credits from market value studies is 0.35.

Inconsistencies between the AER's approach to the treatment of imputation credits in the Dividend Discount Model and the Post Tax Revenue Model

In its Guideline materials, the AER notes the following concern expressed by SFG Consulting (2013):

"The way in which the AER accounts for imputation benefits in its dividend discount model is inconsistent with the way in which the AER accounts for imputation benefits in its post-tax revenue model."[261]

The point being made here is that the PTRM reduces the AER's estimate of the with-imputation required return on equity by a factor of

$$\frac{1 - T}{1 - T(1 - y)}$$

to obtain an estimate of the ex-imputation required return on equity. The AER then allows the regulated firm to charge prices so that the firm is able to provide that ex-imputation required return to equity holders.

In the example discussed at the beginning of this section, the with-imputation required return is 10% (which equates to \$70 on the \$700 of equity capital). The PTRM reduces this to:

$$r_{ex} = r_{with} \frac{1 - T}{1 - T(1 - y)}$$

$$= 10\% \frac{1 - 0.3}{1 - 0.3(1 - 0.25)} = 9.032\%$$

(which equates to \$63.23 on the \$700 of equity capital). That is, the PTRM assumes that imputation credits provide a return of 0.97% (or \$6.77) in accordance with the table above and with the Officer adjustment formula set out above.

This whole procedure starts with the AER's estimate of the with-imputation required return on equity. That is, the PTRM takes the with-imputation required return on equity as an input.

A problem arises if the AER's estimate of the with-imputation required return on equity is based on imputation credits providing a return different from the figure that is used in the PTRM. Suppose, for example, that the AER initially estimates the with-imputation required return on equity on the basis of imputation credits providing a return of 0.5% p.a., when the PTRM assumes that imputation credits provide a return of 0.97% p.a. Such a combination of estimates would obviously be inconsistent and wrong, and would lead to equity holders being systematically under-compensated. In this case, the AER would have commenced with an ex-imputation estimate of 9.5% and increased it to a with-imputation return of 10% on the basis of a 0.5% return from imputation credits. If the AER then used the PTRM to reduce the 10% with-imputation return to a 9.03% ex-imputation return, there is a clear and demonstrable inconsistency that leaves equity holders out of pocket.

The point is simply that there must be a consistency between:

- The return from imputation credits that is embedded into the AER's initial estimate of the with-imputation required return on equity (the input into the PTRM); and
- The return from imputation credits that is factored into the PTRM.

SFG Consulting (2013) note that, in relation to DDM, the AER proposes to estimate its with-imputation required return using one approach for determining the return from imputation credits, when the PTRM uses a different (inconsistent) approach.

On this point, McKenzie and Partington (2013) state that:

"If the foregoing is accepted as an accurate description of the AER's proposed practice, then SFG is correct in concluding that there is an inconsistency in the approach that the AER applies in computing the estimated cost of corporate tax and that applied in their DDM imputation adjustment."[262]

The AER states that:

"There is a diversity of views on this question. On the one hand, McKenzie and Partington provide support, albeit qualified support, for SFG's view, concluding that if SFG has accurately characterised our revenue model, then SFG are correct. On the other hand, Lally concurs with our formula for adjusting for imputation credits."[263]

261 SFG Consulting, Reconciliation of Dividend Discount Model Estimates with those Compiled by the AER , October 2013, p. 30.

262 Michael McKenzie and Graham Partington, Report to the AER: 'The Dividend Discount Model (DDM)', December, 2013, p. 23.

263 AER Rate of Return Guideline, Explanatory Statement, Appendix E, p. 125.

However, Lally (2013) does not address the inconsistency issue at all. His paper does not consider the fact that the AER's approach for estimating the with-imputation required return on equity is inconsistent with the PTRM. To suggest that Lally has endorsed the internally inconsistent approach that the AER has proposed would be disingenuous and misleading. Lally (2013) does no more than consider the AER's approach for estimating the with-imputation required return on equity. In our view, the logical conclusion from the Lally (2013) report is that this same adjustment for imputation credits should be applied consistently wherever an adjustment for imputation credits is required — not that different (inconsistent) adjustments for imputation credits should be applied in different steps of the same estimation process.

Nevertheless, the AER concludes that:

"Given the variety of views on this question, we propose to use the imputation adjustment from the draft explanatory statement, but we will continue to consider this issue."[264]

It is important that a consistent approach is found to the treatment of imputation credits in the PTRM and the application of the Dividend Discount Model and we look forward to a constructive consultation with the AER on how it proposes this should be achieved.

26.5

Allowed rate of return for debt

The relevant issues in determining an allowed rate of return for debt are:

- What should be the tenor of the benchmark debt?
- What should the credit rating be?
- Should the allowance for debt be set using the 'on the day' method or the trailing average method and should the allowance be updated annually or achieved via a 'true up' at the conclusion of the regulatory period?
- Should there be a transition to the trailing average method?
- What should be the data source for the relevant market interest rates?
- How should the data be extrapolated, if required?
- What should be the averaging periods over which the data is sourced for each annual update?
- Should a new issue premium be added to these estimates?
- What should be the mechanism and timing for the annual updating?

Each of these questions is addressed below.

Tenor of the benchmark debt instrument

The Guideline adopts a 10 year tenor for the debt portfolio of the benchmark efficient firm based on a review by the AER of actual debt portfolios of comparable businesses.

SA Power Networks agrees with the position in the Guideline and that the benchmark entity's debt portfolio comprises long dated bonds to match the long run nature of network capital investments to minimise refinancing risk.

264 AER Rate of Return Guideline, Explanatory Statement, Appendix E, p. 125.

Benchmark credit rating

The Guideline considers that the benchmark credit rating should be BBB+ but in the data provided to the AER as part of the guideline process it is evident that the median rating of comparable firms is currently only BBB. It is unclear as to why this therefore does not represent the appropriate credit rating for a benchmark efficient firm. Based on the evidence provided, we consider the appropriate benchmark credit rating for an efficient firm is BBB.

Moving over time to the trailing average method

The trailing average approach recognises that in practice a firm's actual cost of debt will be determined by historic rates and energy networks do not raise all their capital at one time and instead have staggered debt maturities. In practice, energy network businesses need to balance a number of considerations when determining how much debt to refinance at what times, including:

- Diversification of debt instruments and maturities;
- Liquidity management;
- The requirement by credit rating agencies to have committed funding in place well in advance of maturing debt or new debt requirements;
- Having sufficient funding in place to accommodate future growth in the Regulatory Asset Base;
- Credit metrics; and
- Market conditions.

For this reason, in practice firms will have different amounts of debt maturing at different points in time. Nevertheless, the trailing average approach is likely to more closely align with the staggered approach to refinancing a debt portfolio than the 'on the day' method albeit that the trailing average method is a substantial simplification of what actually occurs.

The trailing average approach significantly reduces the risk that prices for customers on a given network might be higher or lower than the average interest rate over time simply because the 'on the day' rate for their particular service provider occurred at a high or low point in interest rate movements.

SA Power Networks therefore accepts the concept of the 10 year trailing average set out in the Guideline.

At one stage during the Guideline consultation process, the possibility of a 'true up' at the conclusion of the regulatory period was canvassed as a possibility rather than annual updating. We consider that annual updating is an important feature of moving to a trailing average approach because otherwise the two principle advantages of the trailing average would not be fully obtained (ie more closely matching the regulatory allowance to a portfolio of progressively refinanced debt and delivering customer prices that more closely track the evolution of market interest rates).

The Guideline proposes that the new trailing average method be introduced gradually and we accept that proposal. In the first year, the rate for debt would be set in the manner that applied in the previous determination (ie the 'on the day' method). In the second regulatory year of the control period, a weighted average will be calculated with 90% weight accorded to the figure determined at the outset of the regulatory period and 10% weight given to the prevailing interest rate at the time of the second regulatory year.[265] In the third year, the weighted average will be calculated with an 80% weight accorded to the figure determined at the outset of the regulatory period, 10% in the second year of the regulatory period and 10% at the time of the third year and so on.

After a 10 year transition period (ie by the end of the second RCP) the rate for debt would be set using a weighted average in which the current year and each of the preceding nine years would each have a 10% weighting.

Source of data

The Guideline did not express a definitive proposal as to the source of the data for the benchmark return on debt. The AER is currently consulting on the appropriate source of data which could be drawn from an independent third party provider or from methods such as Nelson-Seigel. The AER has noted that the use of independent third party estimates may be less controversial where the published source is already available and not explicitly constructed for the regulatory process.

There are currently two principal options for independently published BBB yield estimates under consideration. Namely, the Bloomberg BBB BVAL curve and the RBA published aggregate measure of 10 year Australian BBB corporate debt.[266] Although neither curve publishes an estimate for 10 year debt, the Bloomberg service produces a 7 year fair value estimate, and the RBA's publication provides a fair value estimate for a 'target tenor' of 10 years but, because most bonds in its sample are less than 10 years, this is generally associated with a published "effective tenor" of less than 10 years. Extrapolation can be used to arrive at a 10 year figure for both published yield estimates.

On the information reviewed by SA Power Networks to date, it appears that both service providers currently have similar estimates and it does not appear that either of these service providers should be favoured over the other. On that basis our Proposal gives a 50% weighting to each of the Bloomberg BBB BVAL (extrapolated out from 7 to 10 years) and RBA published series.

Nevertheless, it is possible that in the future there may be reason why one service provider's data may be better suited to the task of setting an allowed return on debt than another service provider. In the past it has not always been transparent how a third party performs its calculations and flaws have been discovered in the way the calculations are performed after the regulatory decision has been made — for example, flaws in the CBA Spectrum service lead to the revocation and substitution of several revenue determinations in 2005.

Should further information emerge during the consultation period that demonstrates one or other service to be superior, SA Power Networks would provide that information to the AER with a recommendation on what changes (if any) should be made to the 50% weighting accorded to each of the two services.

265 A proxy for the prevailing interest rate in any regulatory year will be taken by measuring the cost of debt over an averaging period in the prior year.

266 RBA, Aggregate Measures of Australian Corporate Bond Spreads and Yields — F3.

Extrapolation of the Bloomberg BBB BVAL and RBA series to produce 10 year quotations

As already discussed, the Bloomberg BBB BVAL curve is only published to 7 years. Similarly, the RBA series is published with the longest 'effective tenor' generally being less than 10 years.

If, as is currently the case, the longest dated maturity of the published curves is less than 10 years the yield at 10 years will be estimated as the prevailing swap rate at 10 years maturity (which is published by both Bloomberg and the RBA)[267] plus the extrapolated debt risk premium relative to the swap rate (DRP) at 10 years.

The extrapolated DRP will be estimated as:

- the DRP at the longest published maturity for each curve; plus
- the product of:
  - the average slope of the DRP with respect to changes in maturity at each point on the published yield curve at or above 1 year maturity; and
  - the difference between 10 years and the longest dated maturity on the published yield curve.

If the longest dated maturity of the published curves is greater than 10 years (for example if longer dated bonds are issued and the RBA's 'effective tenor' exceeds 10 years) then the yield at 10 years will be estimated as the prevailing swap rate at 10 years maturity of that service provider plus an estimate of the 10 year DRP using interpolation of the DRP (measured relative to swap rates) between the two points on the published curve closest to, but on either side of, a 10 year maturity.

Averaging period

The Guideline[268] proposes that there be an averaging period set for each year of the regulatory control period from which the data for the allowed return on debt will be drawn. The Guideline states that the periods can be proposed by the service provider in its initial regulatory proposal and agreed by the AER on a confidential basis.

Accompanying this Proposal and forming part of it is a confidential letter proposing an averaging period for each year of the regulatory Proposal.

For illustrative purposes, the figures presented in this proposal use RBA series debt data calculated using a 20 business day period ending on 29 August 2014. The RBA currently only publishes its yield estimates for the last day of every month. In this circumstance the extrapolated yield is estimated for each of the relevant end of month estimates and straight line interpolation is used to arrive at an estimate of the cost of debt over the specific averaging period.

267 When performing this calculation using RBA data the swap rate at 10 years can be calculated from the RBA publication by subtracting the published BBB 'Spread to swap — 10 year' from the published BBB 'Yield — 10 year'. Similarly, Bloomberg also publishes its own estimates of the swap rate at 10 years. In order to preserve internal consistency, for the purpose of extrapolating the RBA/Bloomberg yields the estimated swap rate should be sourced from the RBA/Bloomberg respectively.

268 AER Rate of Return Guideline, pp. 21–22.

Bloomberg publishes its estimates daily and, consequently, a simple average of the daily estimates during the averaging period is used.

New issue premium

The proposed sources of debt data (ie the RBA and Bloomberg series) are observations of the secondary debt market — that is the market in which debt issued in the past but which has not yet reached maturity is sold from one bond holder to another.

By contrast, when network businesses raise debt it is by issuing new bonds to bond holders. This is known as the primary market. There are a number of differences between the primary and secondary bond markets. For example, the quantum of debt that is the subject of an issue is much greater than the later secondary trade in bonds with only a small proportion (if any) re-traded each business day.

The difference between the costs facing a business issuing bonds into the primary debt market and trading in the secondary debt market is commonly referred to as the "new issue premium". It is accepted that this premium is, on average, positive — due to reasons identified in the literature such as the critical importance of avoiding a failed primary bond issue.

At the time of writing, CEG is in the process of preparing a report concerning its views on the size of the new issue premium.[269] The new issue premium is measured as the change in yields from issue relative to changes in yields of a bond market index. Both the Bloomberg BBB BVAL fair value curve and the RBA BBB fair value curve are calculated based on Bloomberg indicative yields. CEG's advice is that for this purpose the yields used should reflect published indicative yields rather than yields based on traded prices.

This advice reflects CEG's view that given that the new issue premium would be applied to fair value estimates derived from published indicative yields, it should calculated in a fashion consistent with its application.

SA Power Networks understands that approximate size of the new issue premium estimated by CEG is in the order of 30 basis points and this figure is used in our regulatory proposal. SA Power Networks will review the CEG report once it is available and it is this figure that should ultimately be used in the setting of the cost of debt allowance.

Formulae

NER 6.5.2(l) requires that the above concepts be given effect to by[270]:

"the automatic application of a formula that is specified in the distribution determination."

The interpretation provisions in the National Electricity Rules provides that the reference to "a formula" includes a reference to the plural "formulae".

The extrapolation formula is as follows:

For each service provider the average slope of the DRP with respect to changes in maturity at each point on the published yield curve at or above 1 year maturity is estimated as the slope coefficient using ordinary least squares (OLS) regression on observations of fair value DRP against maturity with an intercept term. That is, the formula below:

Average slope = $\frac{\sum_{i=1}^{n}(DRP_i - \overline{DRP})(M_i - \overline{M})}{\sum_{i=1}^{n}(M_i - M)^2}$; where

DRP_i = published yield at maturity of 'i' years less the swap rate at maturity 'i' based on data published by the relevant service provider;
$\overline{DRP}$ = the mean of all DRP_i for 'i' greater than or equal to 1;
M_i = is the maturity of 'i' years associated with DRP_i (in the context of the RBA publication this is effective maturity);
$\overline{M}$ = the mean of all M_i for 'i' greater than or equal to 1;
n = the number of observations of fair value DRPs with maturity greater than or equal to 1.

The extrapolated DRP at 10 years is given by:

$DRP_{10} = DRP_{i\,max}$ + (Average slope)×(10 - i_{max})

Where i_{max} is the longest maturity associated with a published yield.

The extrapolated yield at 10 years is given by:

Extrapolated yield = 10 year swap rate + DRP_{10}

The RBA publishes the DRP to swap at each maturity and the yield at each maturity, so the implied swap rate at each maturity to be used for RBA data can be calculated as:

$Swap_i = Yield_i - DRP_i$

Bloomberg publishes swap rates that can be sourced through the ADSWAP fields within the Bloomberg environment. For example, "ADSWAP1 Index" is the field for Australian swap rates with 1 year to maturity.

269 CEG 'New Issue Premium', 2014.

270 Schedule 2 of the NEL provides that the above reference to a single formula also includes a reference to formulae in the plural see Section 11(4)(a).

The formula to be used for each of the years of the regulatory period is as follows:

Financial Year 2015/16:
$kd_{2015-16} = R_{2015-16} + NIP$

Financial Year 2016/17:
$kd_{2016-17} = (0.9 \times R_{2015-16}) + (0.1 \times R_{2016-17}) + NIP$

Financial Year 2017/18:
$kd_{2017-18} = (0.8 \times R_{2015-16}) + (0.1 \times R_{2016-17}) + (0.1 \times R_{2017-18}) + NIP$

Financial Year 2018/19:
$kd_{2018-19} = (0.7 \times R_{2015-16}) + (0.1 \times R_{2016-17}) + (0.1 \times R_{2017-18}) + (0.1 \times R_{2018-19}) + NIP$

Financial Year 2019/20:
$kd_{2019-20} = (0.6 \times R_{2015-16}) + (0.1 \times R_{2016-17}) + (0.1 \times R_{2017-18}) + (0.1 \times R_{2018-19}) + (0.1 \times R_{2019-20}) + NIP$

where:

kd_t — is the return on debt for Financial Year t of the RCP.
$R_{2015-16}$ — is ((the annual return on debt observation for Financial Year 2015/16 from Bloomberg BBB BVAL) + (the annual return on debt observation for Financial Year 2015/16 from the RBA series) x 0.5
R_t — is ((the annual return on debt observation for Financial Year t from Bloomberg BBB BVAL) + (the annual return on debt observation for Financial Year t from the RBA series) x 0.5 where t>2015/16
NIP — is the estimate of the new issue premium of 30 basis points.

SA Power Networks notes that the above formulae have not been used in its previous regulatory determinations and the AER's consultation on our Proposal will provide an opportunity for us to 'road test' that the formulae properly express the points discussed in this chapter of the Proposal before the AER makes its final decision.

Annual update process
The Rules already provide that SA Power Networks must submit its tariffs to the AER each year for approval and, in doing so, the AER will also have the opportunity to review and approve SA Power Networks' implementation of the annual updating.

SA Power Networks also notes that there is currently a Rule change being considered by the AEMC with a decision due in November 2014. It is expected that the tariff approval process will be brought forward which has implications for the timing of the averaging period and the calculation of the trailing average return on debt. It may be possible to cater for the timing implications of that Rule change in the AER's final decision on our Proposal or there may need to be a transitionary arrangement included in the AEMC Rule change process.

26.6

SA Power Networks' proposed WACC parameters

In summary, using data for the 20 business days to 31 August 2014 averaging period, the following would be the WACC parameters:

Table 26.11: Proposed WACC parameters

Primary method for determining equity:	
Aggregate information	
Value of a distributed credit (theta)	0.35
Distribution rate	0.70
Value of a dollar of corporate tax paid (gamma, rounded to nearest 0.05)	0.25
Ratio of return from dividends and capital gains to total return in the AER post-tax revenue model	0.9032
Risk-free rate	[3.43%]
Market risk premium	[7.72%]
Market return	[11.15%]
Cost of equity under alternative models	
Sharpe-Lintner Capital Asset Pricing Model	[9.74%]
Black CAPM	[10.35%]
Fama-French Model	[10.57%]
Dividend discount model	[10.72%]
Weighted average cost of equity estimate	[10.45%]
Alternative method for determining equity	
Equivalent beta under the Sharpe-Lintner CAPM foundation model	
Sharpe-Lintner Capital Asset Pricing Model	[0.82]
Black CAPM	[0.90]
Fama-French Model	[0.93]
Dividend discount model	[0.94]
Weighted average beta estimate	[0.91]
Foundation CAPM estimate of cost of equity	[10.45%]
Debt and other	
Bloomberg BBB BVAL	[5.29%]
RBA	[5.60%]
50%:50% weighting	[5.44%]
New Issue Premium	[0.30%]
Debt allowance	[5.74%]
Gearing*	60%
Expected Inflation rate**	[2.55%]
Nominal Vanilla WACC	[7.62%]

* AER Rate of Return Guideline

** The CPI assumption is based on a geometric mean 10 year forecast, as per the AER standard methodology. It applies the CPI Forecast to June 2016 from the May 2014 Reserve Bank of Australia, Statement on Monetary Policy and assumes a return to 2.5% Reserve Bank target mid-point CPI thereafter. CPI assumption will be updated with the most recently available forecasts for the Draft Determination and Final Determination.

27 Depreciation

27

In this chapter of the Proposal, SA Power Networks presents its forecast of depreciation for the current and future RCPs. SA Power Networks has forecast its depreciation allowance at an asset category level using straight-line depreciation with all assets within each class assigned weighted average standard and remaining lives.

The Post-tax Revenue Model (**PTRM**) has been used to calculate both the regulatory and tax depreciation allowances. This approach is consistent with the requirements set out in Clauses 6.5.5 and S6.1.3 of the Rules.

The completed PTRM is provided as Attachment 25.2 to this Proposal.

27.1

Rule requirements

The Rules at clause 6.4.3 provide that the annual revenue requirement must be determined using a building block approach, which includes a component for depreciation calculated pursuant to clause 6.5.5. In particular:

- subclause 6.5.5(a)(1) requires that depreciation must be calculated based on the value of the regulatory asset base (**RAB**) at the beginning of each year;
- subclause 6.5.5(a)(2) requires depreciation to be calculated using depreciation schedules nominated by the DNSP in the building block proposal;
- subclause 6.5.5(b)(1) requires that depreciation schedules must be based on the economic life of the assets;
- subclause 6.5.5(b)(2) requires that the recovery of depreciation must maintain net present value neutrality over the life of the asset; and
- subclause 6.5.5(b)(3) requires that the economic life, depreciation rates and methods underpinning the calculation of depreciation for a RCP must be consistent with the distribution determination for that period.

In addition, clause S6.1.3(12) requires the depreciation schedules nominated by the DNSP to be categorised by asset class or category driver, together with details and an explanation of the amounts, values and other inputs used to compile the depreciation schedules, and a demonstration that the depreciation schedules conform with the requirements set out in clause 6.5.5(b) of the Rules.

27.2

Depreciation methodology

The Rules provide general guidance for the determination of regulatory depreciation. Whilst a specific depreciation methodology is not provided in the Rules, the PTRM issued by the AER in accordance with the Rules, contains a specific depreciation calculation methodology.

The AER's preferred approach to calculate the depreciation allowance is by straight line depreciation. This is consistent with the methodology applied by SA Power Networks in the current RCP and SA Power Networks proposes to continue to apply this depreciation methodology in the 2015–20 RCP.

SA Power Networks has used the AER's PTRM to calculate depreciation in accordance with Clause 6.5.5 of the Rules. New assets are depreciated according to standard lives for each asset class. Existing assets are depreciated over their remaining asset lives. Opening asset values at 1 July 2015 have been calculated applying the AER's Roll Forward Model (**RFM**).

27.3

Asset categories

In the 2015–20 RCP, SA Power Networks proposes the addition of one new asset class, the removal of one asset class and a change in treatment for an existing asset class. These changes are discussed below.

It is proposed that there be no other changes to the existing asset class categorisations.

Vehicles

Vehicles are currently allocated to two asset classes, Light Vehicles with a depreciation life for regulatory purposes of five years and Heavy Vehicles with a depreciation life for regulatory purposes of 20 years. In the current RCP, SA Power Networks has revised its' replacement policy for Elevated Work Platform vehicles (**EWP**) to 10 years and cranes to 14 years. The replacement policy for other commercial vehicles such as trucks will change from 20 years to 15 years during the 2015–20 RCP. These vehicles are currently allocated to the Heavy Vehicle asset category. The new replacement policies are not consistent with the 20 year regulatory depreciation life for the Heavy Vehicle category.

SA Power Networks has created a new asset class named 'Vehicles — 10 year', with a 10 year regulatory depreciation life, so as to more accurately reflect the planned replacement cycle of these assets. The existing 'Heavy Vehicles' asset category will be renamed 'Vehicles – 15 year' and its standard life revised from 20 years to 15, to reflect the revised replacement policy for other heavy vehicles, predominantly trucks and cranes. The regulatory written down value of Heavy Vehicles as at 1 July 2015 has been left in the renamed Vehicles — 15 year asset class to avoid the need for assumptions in relation to the historic mix of assets. Only new expenditure from 1 July 2015 on vehicles with a 10 year replacement life will be allocated to the new Vehicles — 10 years asset category. The replacement policy for passenger vehicles will also change from five to four years during the 2015–20 RCP, to align to good industry practice.

Work in progress

As discussed in Chapter 25, Regulated Asset Base, the balance of Work in Progress at 30 June 2015 will be allocated to the asset categories to which the expenditure relates, so as to transition to depreciation on an as incurred basis. Consequently the PTRM for 2015–2020 does not contain a Work in Progress asset category.

Contributed assets

Common regulatory practice is to allocate contributed assets to the asset classes to which they relate, less the value of contribution received. This results in net capex being appropriately allocated against each asset class.

Since commencement of regulation by ESCoSA, SA Power Networks has applied a variation of this methodology, whereby the value of contributions received has been allocated to a separate 'Contributions' asset class. This asset class has a negative balance and is depreciated over an weighted average life for the network assets to which they relate.

In order to move to a methodology consistent with national regulatory practice, SA Power Networks will allocate the value of contributions received from 1 July 2015 against the asset class to which the contributions relate. This will result in future net capex being accurately allocated against each asset class.

The regulatory written down value of the existing Contributions asset class will be depreciated over its remaining life to avoid the need for assumptions in relation to the historic mix of assets.

Meter reading devices

A new asset class is proposed for Meter Reading Devices (Alternative Control Services), with a standard life of three years for RAB and tax depreciation purposes.

27.4

Standard and remaining asset lives

Clause 6.5.5(b)(1) requires that depreciation must be based on the economic life of the assets or category of assets. This permits a DNSP to have its capital returned at a rate which is consistent with the decline in economic value of the assets.

The economic life of an asset is the estimated period that the asset will be able to be used in its current, or intended, function in the business.

With the exception of the new asset class noted above, SA Power Networks has applied the same asset lives for the 2015–20 RCP as in the current RCP. There have been no factors identified that would suggest that the expected life of assets utilised by SA Power Networks has changed materially.

The remaining life of existing assets at 1 July 2015 has been determined on a weighted average basis for each asset class, consistent with the methodology applied for the current RCP.

Table 27.1 provides the standard and remaining asset lives (for assets held at 1 July 2015) for each asset class.

Table 27.1: Standard and remaining asset lives

Asset Class	Standard Life (Years)	Average Remaining Life (Years)
System assets		
Sub-transmission lines and cables	55.0	50.5
Distribution lines and cables	55.0	21.1
Distribution transformers	45.0	22.0
Substations	45.0	18.4
Low Voltage Supply	55.0	18.8
Communications	15.0	7.6
Land	N/A	N/A
Easements	N/A	N/A
Net Customer Contributions	N/A [271]	34.4
Non-system assets		
Information systems	5.0	5.0
Plant and tools/Furniture & fittings	10.0	7.6
Vehicles — 15 Years	15.0	11.7
Vehicles — 10 Years	10.0	10.0
Vehicles — light fleet	5.0	5.0
Buildings	40.0	24.9
Land	N/A	N/A
Equity Raising Costs	52.3	48.1
Alternative Control Services		
Meters	15.0	10.6
Meter Reading Devices	3.0	3.0
Equity Raising Costs — Alternative Control	15.0	10.9

271 From 1 July 2015, Contributions will be allocated against the asset class to which they relate.

27.5

Regulatory depreciation for the 2010–15 RCP

In accordance with the Rules, the AER has released a Roll Forward Model to be used to roll forward the RAB for the current RCP. SA Power Networks has utilised the RFM to determine actual regulatory depreciation for the current RCP and the RAB balance at 30 June 2015.

The RAB roll forward methodology in the RFM requires regulatory depreciation to be recalculated on the actual capital expenditure incurred plus forecast capital expenditure (where actual is not available) over the current RCP. In accordance with Clause 6.5.5(b)(3) of the Rules, the actual depreciation has been calculated in accordance with the rates and methods allowed in the distribution determination for the current RCP, and is shown in Table 27.2.

Table 27.2: Regulatory Depreciation for the 2010–2015 Regulatory Control Period

Nominal $ Million	2010/11	2011/12	2012/13	2013/14	2014/15
Standard Control Services	74.1	134.7	121.1	118.9	168.5
Alternative Control Services	3.0	4.8	4.5	4.6	5.8

27.6

Forecast regulatory depreciation for the 2015–20 RCP

SA Power Networks has prepared its depreciation forecast for the 2015–20 RCP, applying forecast asset additions, forecast asset disposals and applying the asset lives listed in Table 27.1. The opening asset balances were determined using the AER's roll forward model. The AER's PTRM has been used to calculate the depreciation on a straight line basis.

The total of the resulting regulatory depreciation allowance is shown in Table 27.3.

Table 27.3: Forecast Regulatory Depreciation 2015–20

Nominal $ Million	2015/16	2016/17	2017/18	2018/19	2019/20
Standard Control Services	132.3	161.3	188.6	215.5	238.3
Alternative Control Services	6.1	7.0	7.9	9.5	10.5

27.7

Tax depreciation for the 2010–15 and 2015–20 RCPs

For the purposes of forecasting the cost of corporate income tax pursuant to Clause 6.5.3 of the Rules, SA Power Networks has calculated tax depreciation. Different asset lives apply for taxation purposes under Australian tax law. The AER's PTRM has been used to calculate the tax depreciation on a straight line basis, using applicable straight line tax depreciation rates.

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 27.4 and 27.5 below.

Chapter 28 provides further details on the allowance for corporate income tax.

Table 27.4: Tax Depreciation 2010–15

Nominal $ Million	2010/11	2011/12	2012/13	2013/14	2014/15
Standard Control Services	65.9	76.5	97.5	113.7	133.0
Alternative Control Services	3.0	3.2	3.4	3.5	3.7

Table 27.5: Forecast Tax Depreciation 2015–20

Nominal $ Million	2015/16	2016/17	2017/18	2018/19	2019/20
Standard Control Services	134.3	172.0	207.4	241.1	273.3
Alternative Control Services	4.2	4.9	5.7	7.2	8.2

28 Estimated cost of corporate income tax

28

In this chapter of the Proposal, SA Power Networks sets out its estimated cost of corporate tax for the 2015–20 RCP.

28.1

Rule requirements

Section 6.5.3 of the Rules requires the estimated cost of corporate income tax to be calculated for each regulatory year in accordance with the formula:

$ETCt = (ETIt \times rt)(1 - y)$

where:

- ETIt 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 standard control services if such an entity, rather than the Distribution Network Service Provider, operated the business of the Distribution Network Service Provider, such estimate being determined in accordance with the post-tax revenue model;
- rt is the expected statutory income tax rate for that regulatory year as determined by the AER; and
- y is the value of imputation credits.

For these purposes:

1) The cost of debt must be based on that of a benchmark efficient Distribution Network Service Provider; and
2) The estimate must take into account the estimated depreciation for that regulatory year for tax purposes, for a benchmark efficient Distribution Network Service Provider, of assets where the value of those assets is included in the regulatory asset base for the relevant distribution system for that regulatory year.

A key element of the above Rules is that the allowance for tax must be that of the 'benchmark efficient entity' for the provision of 'standard control services'. Differences arise between these regulatory concepts and actual tax filings because the filings concern real businesses with a different range of activities.

This chapter of the Proposal sets out the methodology for ascertaining the ETCt and estimated tax costs for SA Power Networks.

28.2

Tax depreciation

The value of the tax asset base at 30 June 2015 is determined by applying the prime cost (straight line) method of depreciation. The tax rate to be applied to individual asset categories is that reflected in Australian Tax Office rulings and guidelines at the time the relevant asset was first installed ready for use in the operation of the distribution network in South Australia, as shown in Table 28.1.

Table 28.1: Tax depreciation lives

Asset Class	Prime Cost Tax Depreciation Rate (Years)	Average Remaining Life (Years)
Standard Control Services		
Sub-transmission lines and cables	47.5	34.5
Distribution lines and cables	47.5	27.1
Substations	40.0	28.3
Distribution transformers	40.0	30.9
Low Voltage Supply	47.5	28.0
Communications	10.0	8.1
Contributions	N/A	37.1
Vehicles — 15 years	15.0	11.5
Vehicles — 10 years	15.0	15.0
Light Vehicles	6.7	5.9
IT Assets	4.0	4.0
Plant & Tools/Furniture & fittings	10.0	7.5
Buildings	40.0	40.0
Equity raising costs	5.0	5.0
Alternative Control Services		
Meters	25.0	16.6
Meter Reading Devices	3.0	N/A
Equity raising costs — Alternative Control	5.0	5.0

28.3

Estimated costs of corporate income tax for the 2015–20 RCP

Based on methodology described in this chapter, the tax asset base roll forward has been calculated in tables below.

Table 28.2: Tax Asset Base roll forward to 2015 — Standard Control Services, ($ million, nominal)

	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Opening Tax Asset Base	948.4	1,192.2	1,493.6	1,820.7	2,115.2	2,361.7
Plus capital expenditure, net of disposals	304.2	367.4	403.5	391.9	360.2	473.0
Less regulatory tax depreciation	(60.5)	(65.9)	(76.5)	(97.5)	(113.7)	(133.0)
Closing Tax Asset Base	1,192.2	1,493.6	1,820.7	2,115.2	2,361.7	2,701.7

Table 28.3: Tax Asset Base roll forward to 2015 — Alternative Control Services, ($ million, nominal)

	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Opening Tax Asset Base	51.8	57.9	58.7	59.5	60.1	60.2
Plus capital expenditure, net of disposals	8.7	3.8	4.0	4.0	3.7	13.0
Less regulatory tax depreciation	(2.7)	(3.0)	(3.2)	(3.4)	(3.5)	(3.7)
Closing Tax Asset Base	57.9	58.7	59.5	60.1	60.2	69.5

Table 28.4: Tax Asset Base roll forward to 2020 — Standard Control Services, ($ million, nominal)

	2015/16	2016/17	2017/18	2018/19	2019/20
Opening Tax Asset Base	2,701.7	3,141.8	3,608.6	4,060.8	4,509.0
Plus capital expenditure, net of disposals	574.4	638.8	659.6	689.2	673.7
Less regulatory tax depreciation	(134.3)	(172.0)	(207.4)	(241.1)	(273.3)
Closing Tax Asset Base	3,141.8	3,608.6	4,060.8	4,509.0	4,909.4

Table 28.5: Tax Asset Base roll forward to 2020 — Alternative Control Services, ($ million, nominal)

	2015/16	2016/17	2017/18	2018/19	2019/20
Opening Tax Asset Base	69.5	81.5	94.8	114.3	132.2
Plus capital expenditure, net of disposals	16.3	18.1	25.3	25.0	22.5
Less regulatory tax depreciation	(4.2)	(4.9)	(5.7)	(7.2)	(8.2)
Closing Tax Asset Base	81.5	94.8	114.3	132.2	146.4

From these figures, the estimate of the 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 standard control services (**ETIt**) for the purposes of Rule 6.5.3 are provided in Table 28.6.

Table 28.6: Taxable income, ($ million, nominal)

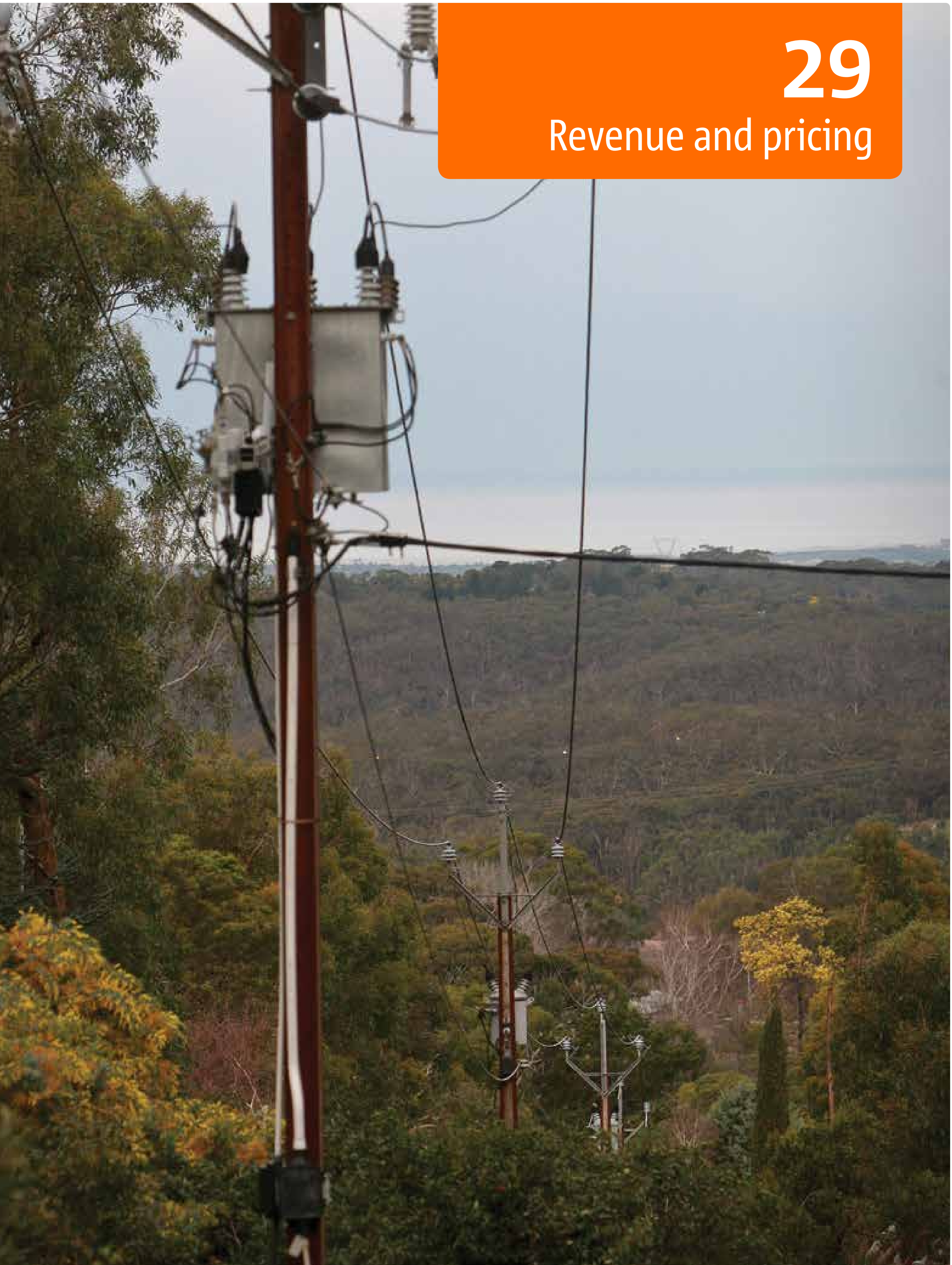
	2015/16	2016/17	2017/18	2018/19	2019/20
Standard Control Services	339.0	350.0	365.9	387.2	406.0
Alternative Control Services	14.8	17.7	24.8	25.3	26.8

Adopting a corporate tax rate (**rt**) of 30% and ascribing a utilisation value for imputation credits (**y**) of 0.25 [as discussed in depth in Chapter 26], the estimated cost of corporate income tax (**ETCt**) for each regulatory year of the 2015–20 RCP is in Table 28.7.

Table 28.7: Estimated cost of corporate income tax, ($ million, nominal)

	2015/16	2016/17	2017/18	2018/19	2019/20
Standard Control Services	76.3	78.8	82.3	87.1	91.3
Alternative Control Services	3.3	4.0	5.6	5.7	6.0

29
Revenue and pricing



29

In this chapter, SA Power Networks sets out its calculation of annual revenue requirements for the provision of Standard Control Services (**SCS**) and Alternative Control Services (**ACS**) for each year of the next RCP. This chapter also sets out the X factors to be applied as part of the revenue cap for the provision of SCS and the price caps for the provision of ACS.

The methodology utilised to derive prices is in accordance with the requirements of Chapter 6 of the National Electricity Rules (**NER**) and employs the AER's Post-Tax Revenue Model (**PTRM**). SA Power Networks' completed SCS PTRM and ACS PTRM are provided as Attachment 25.2 to this Proposal.

Actual prices for SCS will be subject to regulatory adjustments each year for factors including:

- variations in actual CPI from the current 2.55% forecast;
- variations in the annual update of the cost of debt. The AER's Rate of Return Guideline incorporates an annual update to the setting of the cost of debt with the introduction of a 10 year trailing average interest rate. It is likely that the annual cost of debt will differ from that initially forecast in 2015, resulting in some price variations;
- Service Target Performance Incentive Scheme adjustments, which can vary allowed revenues by up to +/-5% in any year, depending on service performance outcomes;
- changes in SCS sales volumes (including variations from both weather effects and underlying growth) which would result in over or under-recovery of allowed revenue; and
- under/over recovery of revenue from the prior year.

Actual prices for ACS will be subject to regulatory adjustments each year for factors including:

- variations in actual CPI from the current 2.55% forecast;
- variations in the adjustments (**'A'**) factor; and
- variations in the annual update of the cost of debt.

Prices are further subject to any tariff re-design that SA Power Networks may propose as part of its pricing proposal to the AER in May 2015. The Australian Energy Market Commission (**AEMC**) has published a draft Rule on pricing arrangements and the final Rule is likely to be approved by the end of 2014, with transitional arrangements expected to apply to SA Power Networks. This new Rule may require:

- changes to the distribution pricing principles that will require prices to be based on long run marginal cost (**LRMC**), rather than the current requirement to take LRMC into account;
- the development of a Tariff Structures Statement (**TSS**), although this is expected to be implemented outside of the 2015 regulatory determination process; and
- possible approaches for pricing non-LRMC costs to those customer segments with greater price elasticity. The intent of such pricing is to maximise the customer response to the LRMC signal, not the avoidance of other tariff elements through inefficient outcomes. (For example, currently when a customer adds a new air-conditioner, the existing tariff does not signal the LRMC network costs and therefore the customer is not receiving the 'correct' pricing signal with the existing tariff).

Whilst the detailed obligations of the new Rule are not finalised at this time, the intent of the AEMC Rule change consultation has been considered in this Proposal.

In addition to SCS charges for SCS and ACS charges for metering services, SA Power Networks' tariffs incorporate pass-through amounts for transmission charges and for approved jurisdictional schemes.

The transmission charges are paid to ElectraNet for the transmission services provided by ElectraNet, MurrayLink and interstate transmission providers which support the South Australian transmission system. The jurisdictional scheme enables the recovery of the South Australian Government's solar photo-voltaic (**PV**) Feed-in Tariff (**FiT**) arrangements which have been paid to customers.

29.1

Revenue and indicative pricing for Standard Control Services

29.1.1 Revenue requirement for Standard Control Services

The annual revenue requirement for SCS, developed utilising the building block approach, comprises a number of components that are discussed in detail in other sections of this Proposal. The forecast recovery of SCS in 2014/15 (including AER-approved pass-through allowances for vegetation management) has been included to allow comparison with the current level of revenue recovered from customers.

The building block components and resulting annual revenue requirement derived from the SCS PTRM[272] are set out in nominal terms in Table 29.1 and in real, June 2015, terms in Table 29.2. The SCS PTRM is provided as Attachment 25.2.

272 SA Power Networks Standard Control Services Post-Tax Revenue Model (Attachment 25.2)

Table 29.1: Building block components — Standard Control Services ($ million, nominal)

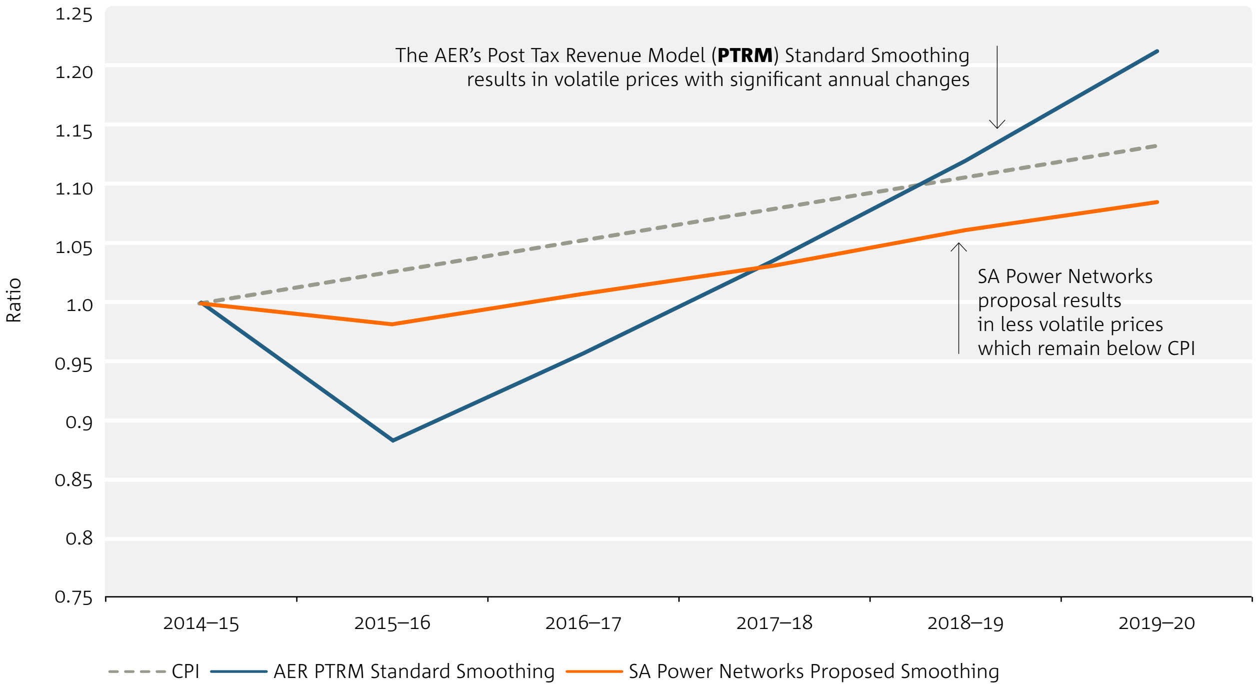
Component	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Return on capital		292.0	318.6	347.8	376.2	404.3
Regulatory depreciation		132.3	161.3	188.6	215.5	238.3
Operating expenditure		292.9	314.3	340.7	358.9	373.2
Carry-over amounts		10.4	17.1	0.1	(13.9)	-
Net shared assets cost reduction		(0.8)	(0.8)	(0.8)	-	-
Tax allowance		76.3	78.8	82.3	87.1	91.3
Unsmoothed revenue requirement		**803.0**	**889.2**	**958.7**	**1,023.9**	**1,107.2**
Smoothed revenue requirement	**918.7**	**901.8**	**924.8**	**948.4**	**972.6**	**997.4**
Revenue P_o and X-factors		**4.3%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**

Table 29.2: Building block components — Standard Control Services (June 2015, $ million)

Component	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Return on capital		284.7	302.9	322.5	340.1	356.4
Regulatory depreciation		129.0	153.4	174.9	194.9	210.1
Operating expenditure		285.7	298.9	315.9	324.5	329.1
Carry-over amounts		10.1	16.3	0.1	(12.6)	-
Net shared assets cost reduction		(0.8)	(0.8)	(0.8)	-	-
Tax allowance		74.4	74.9	76.3	78.8	80.5
Unsmoothed revenue requirement		**783.0**	**845.6**	**888.9**	**925.8**	**976.2**
Smoothed revenue requirements	**918.7**	**879.4**	**879.4**	**879.4**	**879.4**	**879.4**
Revenue P_o and X-factors		**4.3%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**

The P_o reduction and X-factors proposed in Table 29.1 are SA Power Networks' preferred approach to reducing price volatility, in line with AEMC pricing policy objectives. The AER's standard smoothing approach would see more volatile prices with a P_o reduction of 13.4% and subsequent annual real price increases of 5.2%. Refer Figure 29.1.

Figure 29.1: Comparison of SCS price smoothing outcomes ($ nominal)



29.1.2 Pricing proposal for Standard Control Services

SA Power Networks proposes that SCS prices for each year of the 2015–20 RCP be made equal. This approach will deliver a relatively smooth price path within the 2015–20 RCP, noting that prices will be adjusted for CPI and may also vary slightly each year as discussed in the introduction to this chapter.

This price path can be achieved as the outlook for sales growth is forecast at 0.0% (see Section 12.2.1) and can be combined with a revenue cap where X_{1-4} is set to 0.0% following a P_0 of 4.3%. SCS prices would (on average) decline by 4.3% in real terms in 2015/16.

The resulting average price outcomes for each year of the 2015–20 RCP are set out in Table 29.3.

The indicative prices for SCS outlined in this section are forecast to recover revenues equal to, in net present value terms, the unsmoothed revenue requirement for SCS set out in Table 29.1.

Table 29.3: Average annual price outcomes — Standard Control Services

Overall price outcome	2015/16	2016/17	2017/18	2018/19	2019/20
	P_0	X_1	X_2	X_3	X_4
Revenue P_0 and X factors	4.3%	0.0%	0.0%	0.0%	0.0%
Sales Volumes Change	0.0%	0.0%	0.0%	0.0%	0.0%
Average Real Price Change	-4.3%	0.0%	0.0%	0.0%	0.0%

Note: a positive P_0 or X factor represents a real decrease in distribution prices

Indicative annual charges for each tariff class for the next RCP are shown in Table 29.4. The table also assumes that current pricing relativities between tariffs remain.

Table 29.4: Indicative annual charges for Standard Control Services ($ nominal, excl 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

29.2

Other pass-through costs

29.2.1
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 2014/15 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 amount of monies from inter-regional trading differences which are required to be returned to customers via a discount to transmission payments.

It has also been assumed for this Proposal that, following ElectraNet SA's next Revenue Determination in 2018, transmission prices in 2018/19 and 2019/20 will increase with CPI only.

Table 29.5: Indicative transmission costs ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
ElectraNet revenue cap X factor	-2.7%	-2.7%	-2.7%	-2.7%	0% est	0% est
TUoS charges to customers $m	262.6	279.0	293.2	308.1	316.0	324.0

TUOS = TRANSMISSION USE OF SYSTEM

29.2.2
Jurisdictional schemes (PV feed in payments)

The South Australian Government has three 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.

The rate applied to each feed-in scheme is fixed in nominal terms by legislation[273]. SA Power Networks expects payments under the 44 cent schemes to continue at $88.6 million pa until 2028, and the 16 cent scheme to continue at $46.1 million pa until 2016.

Over the 2015–20 RCP, the amount of PV FiT payments recovered from customers will reduce in nominal terms by $73 million. Payments and recoveries are expected to continue at $88.6 million pa through to 2020, and conclude in 2028. See Table 29.6.

273 Electricity (Feed-In Scheme — Solar Systems) Amendments Act 2008; and Electricity (Miscellaneous) Amendment Act 2011

Table 29.6: Indicative PV feed-in scheme costs ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
PV Fit charges to customers $m	161.7	134.6	100.1	88.6	88.6	88.6

29.3

Revenue and indicative pricing for Alternative Control Services

29.3.1 Revenue requirement for Alternative Control Services

We have adopted the building block approach to the determination of the revenue requirements for ACS metering services. The building block approach is the same approach used for establishing revenue requirements for SCS and we have utilised the AER's PTRM for this calculation. The ACS PTRM is provided as Attachment 25.2.

SA Power Networks' forecast capital and operating costs for ACS were outlined in Chapter 20 and 21 respectively. The value of the meter asset base (**MAB**) is set out in the ACS roll-forward model (**RFM**) (Attachment 25.1) and PTRM. These are inputs into the calculation of the ACS revenue requirement for the 2015–20 RCP, which is set out in nominal terms in Table 29.7 and in real, June 2015 terms in Table 29.8.

Table 29.7: Forecast metering building block revenue requirement ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Return on Capital		6.5	6.8	7.1	7.5	7.7
Return of Capital		6.1	7.0	7.9	9.5	10.5
Operating Expenditure		10.4	11.0	22.7	24.1	25.7
Tax Liability		3.3	4.0	5.6	5.7	6.0
Total Unsmoothed revenue	28.0	26.4	28.9	43.3	46.7	49.9

Table 29.8: Forecast metering building block revenue requirement (June 2015, $ million)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Return on Capital		6.3	6.5	6.6	6.8	6.8
Return of Capital		6.0	6.7	7.4	8.5	9.3
Operating Expenditure		10.2	10.5	21.0	21.8	22.7
Tax Liability		3.2	3.8	5.2	5.2	5.3
Total Unsmoothed revenue	28.0	25.7	27.5	40.1	42.3	44.0
SAPN Price Path revenue	28.0	30.0	32.6	35.8	38.5	41.6

29.3.2
Pricing proposal for Alternative Control Services

Using a new Metering Pricing Model (**MPM**), SA Power Networks has developed seven new ACS metering services and tariffs for these services, consistent with the proposed classification of services set out in the AER's Framework and Approach Paper (**F&A**). As no tariff exists for these services in 2014/15, notional or 'seed' tariffs were developed.

SA Power Networks will demonstrate compliance with the ACS price control by proposing tariffs that comply with the price cap formula with its pricing proposal in May of 2015, and in each year of the next RCP.

Indicative prices for the 2015–20 RCP are set out in Table 29.9.

Table 29.9: Indicative metering tariffs ($/year, nominal)

Meter services tariffs	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Provision Type 1–4 'Exceptional' Remotely Read Interval Meter	499	470	489	508	528	549
Provision Reading and Data Type 5–6 current transformer (CT) Connected Manually Read Meter	142	256	266	277	288	299
Provision Reading and Data Type 5–6 whole current (WC) Manually Read Meter	33	33	37	41	45	49
Installation Type 5–6 WC Smart-ready Manually Read Meter (1 phase)	-	295	307	319	331	345
Installation Type 5–6 WC Smart-ready Manually Read Meter (1 phase, 2 element)	-	304	316	328	341	355
Installation Type 5–6 WC Smart-ready Manually Read Meter (3 phase)	-	448	466	484	503	523
Installation Type 5–6 CT Smart-ready Manually Read Meter (3 phase)	-	736	765	795	826	859
Transfer Fee Type 1–4 Exceptional Meter	590	583	576	569	562	555
Transfer Fee Type 5–6 CT Connected Meter	264	261	257	254	251	248
Transfer Fee Type 5–6 WC Smart-ready Meter (1 phase)	-	303	299	296	292	289
Transfer Fee Type 5–6 WC Smart-ready Meter (3 phase)	-	550	543	536	529	522
Exit Fee Type 5–6 WC Standard Meter	-	212	210	207	204	202
Other Meter Provider Customer	0	0	0	0	0	0

The methodology used to develop these tariffs is set out in Attachment 29.3 and the MPM is provided as Attachment 29.4.

29.3.3
Meter transfer and exit fees

In developing this Proposal, SA Power Networks has considered the implications of the Standing Council on Energy and Resources' (**SCER, now the COAG Energy Council**) proposed Rule change in respect of competition in metering services, which is expected to take effect during the 2015–20 RCP.

The Rule change is expected to drive significant change in the metering environment, and SA Power Networks has proposed responses to these changes where prudent to do so, for example, in upgrades to systems to support greater volumes of interval data. However, given the uncertainty in respect of the level of take-up of contestable metering, SA Power Networks has not attempted to forecast the degree of meter churn that may arise from the new Rules in the next RCP; rather, we have sought to manage the volume risk associated with possible churn by way of appropriate meter transfer and exit charges. In this regard, our Proposal reasonably reflects the recommendations in the AEMC's Power of Choice review, which also form the basis of the approach proposed by SCER in its Rule change proposal.

SA Power Networks notes that other options exist for the management of the volume risk posed by the SCER Rule change proposal, and that the AER appears to be open to the consideration of such options, as reflected in its F&A paper[274]. We would be prepared to consider alternative options should the Rule change result in outcomes that are significantly different than are currently expected.

In their Power of Choice review, the AEMC recommended that exit fees should be appropriate, clearly defined and transparent.[275] SA Power Networks' transfer and exit charges are congruent with these principles and with the AER's comments regarding exit fees set out in the F&A.[276]

Existing exit fees

SA Power Networks has had two ACS meter exit fees in place since 2010:

- Meter Service Exit Fee in respect of Type 6 CT connected meters; and
- Meter Service Exit Fee in respect of Type 1–4 Exceptional meters.

The components of these exit charges are:

- administrative costs, which reflect the marginal back-office cost of facilitating the transfer in the relevant systems; and
- meter asset stranding costs, which is the average written down capital value of the specific assets expected to be the subject of metering customer churn.

We currently do not publish or charge an exit fee for Type 6 whole current meter customers changing to another meter provider. The value of these meters remains in the ACS regulated asset base (**RAB**) and is recovered across all remaining customers. This clearly is not a sustainable arrangement as we are likely to move to increased competition in metering during the next RCP.

New charges

We have developed three new transfer and exit charges for the next RCP:

- A transfer fee for 1 phase 'smart ready' meters;
- A transfer fee for 3 phase 'smart ready' meters; and
- An exit fee for basic Type 5 and 6 whole current meter assets in place at the end of the 2010–2015 RCP (legacy meters).

SA Power Networks' Proposal reflects the principle that it is unfair to penalise customers that choose not to churn to another meter provider. Rather than attempting to recover stranded costs by increasing the metering charges to remaining customers, our Proposal provides for the recovery of these costs through an exit fee or meter transfer charge.

The transfer and exit charges reflect the recovery of operating costs incurred for processing transfers and recovering the charge from a customer that has changed their retailer. It also includes the value of the stranded asset (and the associated tax cost), including the meter, and any communications infrastructure. Further, it includes the relevant portion of unavoidable fixed costs, including operating costs that are invariable for the balance of the term of the RCP. Such costs include contracted costs such as for IT infrastructure and meter data management, and corporate overheads.

The legacy meter exit fee reduces during the RCP, reflecting the declining value of the RAB component of this fee as no further legacy meters will be installed after 1 July 2015.

A separate fee is necessary in respect of smart ready meters because the average residual value of these meters will be significantly higher than that of legacy meters, primarily because the remaining economic life will be much higher. The fee is characterised as a transfer fee because a competitive meter provider will have the option to retain and use the existing meter (eg by installing their own telecommunications module) rather than having to replace the meter at a significantly greater cost.

As discussed, SA Power Networks is open to considering options which avoid the imposition of exit fees and reduce the administration costs where meters are transferred or replaced provided these alternative options keep SA Power Networks whole in terms of recovering costs including residual value of meters.

29.4

Total network charges forecast for recovery

The total recovery from all SA Power Networks customers' network charges will comprise the SCS (distribution services) charges, the ACS (metering services) charges and the pass-through charges for transmission and PV FiTs.

Table 29.10 shows SA Power Networks' total Direct Control Services costs (SCS and ACS) in nominal terms. Table 29.11 shows these costs in real June 2015 terms.

The amounts shown assume no SA Power Networks' customers move to another metering services provider.

274 AER, Final Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015, April 2014

275 AEMC, Final Report, Power of choice review — giving consumers options in the way they use electricity, 30 November 2012, pp 83, 89, 92–93.

276 AER, Final Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015, April 2014, p52.

Table 29.10: Forecast Direct Control Services costs 2015–20 RCP ($ million, nominal)

Components	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Standard Control Services	918.7	901.8	924.8	948.4	972.6	997.4
Alternative Control Services	28.0	30.8	34.3	38.6	42.6	47.2
Total network charges	946.7	932.6	959.1	987.0	1,015.2	1,044.6
Revenue P0 and X-factors		3.9%	-0.3%	-0.4%	-0.3%	-0.3%

Table 29.11: Forecast Direct Control Services costs 2015–20 RCP (June 2015, $ million)

Components	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Standard Control Services	918.7	879.4	879.4	879.4	879.4	879.4
Alternative Control Services	28.0	30.0	32.6	35.8	38.5	41.6
Total network charges	946.7	909.4	912.0	915.2	917.9	921.0
Revenue P0 and X-factors		3.9%	-0.3%	-0.4%	-0.3%	-0.3%

Table 29.12: Indicative customer bills for Direct Control Services costs ($, nominal)

Customer type	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)	9,907	9,726	9,976	10,233	10,498	10,769
Small business (10 MWh pa)	1,270	1,248	1,283	1,318	1,355	1,393
Low voltage residential (5 MWh pa)	672	661	680	700	721	743
Controlled load (2.5 MWh pa)	97	95	97	100	102	105

Table 29.13 shows the total costs including transmission charges and the jurisdictional FiT scheme in nominal terms and Table 29.14 shows the total costs in real, June 2015 terms. Table 29.15 shows the typical outcome by customer segment.

Table 29.13: Forecast Direct Control Services costs plus pass-through costs 2015–20 RCP ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Standard Control Services	918.7	901.8	924.8	948.4	972.6	997.4
Alternative Control Services	28.0	30.8	34.3	38.6	42.6	47.2
Transmission charges	262.6	279.0	293.2	308.1	316.0	324.0
PV FiT schemes	161.7	134.6	100.1	88.6	88.6	88.6
Total network charges	1,371.0	1,346.2	1,352.3	1,383.7	1,419.7	1,457.2
Revenue P0 and X-factors		4.3%	2.0%	0.2%	-0.1%	-0.1%

Table 29.14: Forecast Direct Control Services costs plus pass-through costs 2015–20 RCP (June 2015, $ million)

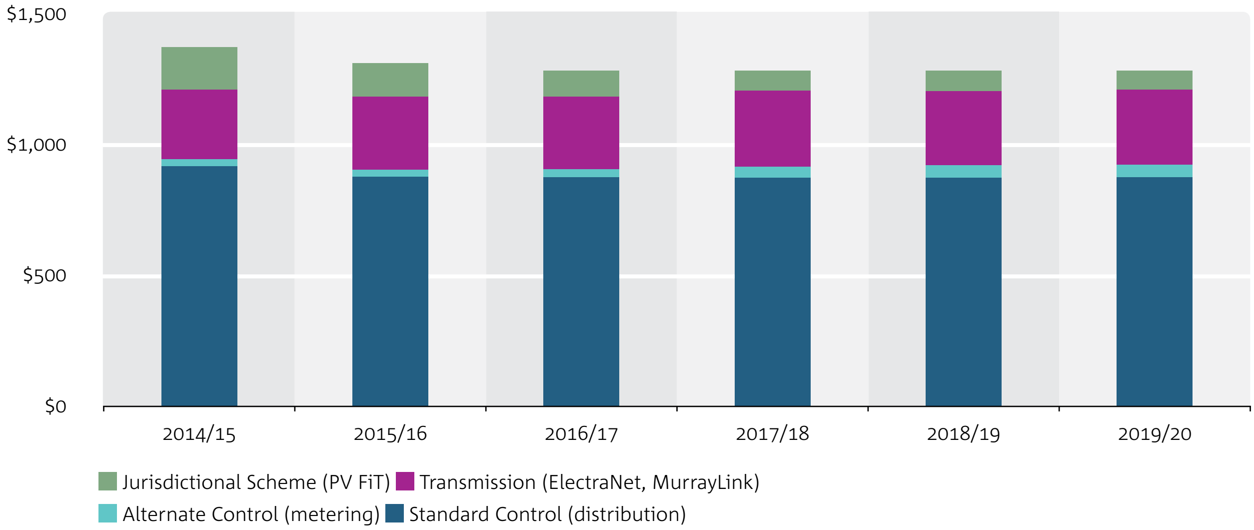
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Standard Control Services	918.7	879.4	879.4	879.4	879.4	879.4
Alternative Control Services	28.0	30.0	32.6	35.8	38.5	41.6
Transmission charges	262.6	272.0	278.8	285.7	285.7	285.7
PV FiT schemes	161.7	131.3	95.2	82.1	80.1	78.1
Total network charges	1,371.0	1,312.7	1,285.9	1,283.0	1,283.7	1,284.8
Revenue P0 and X-factors		4.3%	2.0%	0.2%	-0.1%	-0.1%

Table 29.15: Indicative customer bills for all network service costs ($, nominal)

Customer type	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
High voltage business (2.7 MVA demand, 10 GWh pa)	681,400	673,822	678,963	695,499	712,199	729,326
Low voltage business (360 kVA demand, 1 GWh pa)	110,088	108,087	108,430	110,756	113,398	116,106
Medium business (100 MWh pa, 50% peak)	14,287	13,957	13,953	14,224	14,564	14,914
Small business (10 MWh pa)	1,804	1,764	1,767	1,804	1,850	1,898
Low voltage residential (5 MWh pa)	925	903	905	924	949	975
Controlled load (2.5 MWh pa)	135	132	131	134	137	140

Total network charges are forecast to be lower in real terms across the 2015–20 RCP than they are forecast for 2014/15. Figure 29.2 shows the total costs by network category for SA Power Networks in real terms.

Figure 29.2: Total forecast network charges 2015–20 RCP (June 2015, $ million)



29.5

Network tariffs

29.5.1
Network tariff design

The NER set out the mandatory requirements for network tariff design. Rule 6.18.5 requires that prices for a tariff class must be set between the costs necessary to only supply that tariff class (ie a standalone price) and the costs that could be avoided if that tariff class were not supplied at all. This ensures that tariffs can not be set below the incremental cost to supply these customers and do not exceed the cost of only supplying these customers. However, there is less guidance in the NER about how prices should be set between these two points.

The Rule also requires that the pricing of each tariff element should consider the LRMC of that element of service, the transaction costs of having that tariff element and whether customers are able to respond to the price signal. Any short-fall in revenue recovery from these tariff elements which considered LRMC costs requires tariff amendment by the DNSP. Such tariff amendments should be aimed at minimising distortion from inefficient consumption. The AEMC is expected to finalise a new Rule shortly which will strengthen the requirement for LRMC pricing.

Therefore, network tariffs need to be efficient, effective and simple. Other customers should not have to pay more because of new customers connecting to the network. Tariffs should be structured to promote efficient consumption and should not promote inefficient consumption. The tariff class assignment Rule (see below) requires equity in tariff class application, with similar customers having similar load profiles being assigned to the same tariff.

It is difficult to improve the efficiency of small customer tariff design if energy accumulation is the only usage measure available as has historically been the case. Air conditioning loads comprise 80% of the average customer's demand, which drives network costs, but less than 20% of the energy on which accumulation meters-based tariffs can charge. Also, other Rules have prevented increasing some charges above an annual fixed amount (eg the $10 pa supply charge control applicable to small South Australian customers, which has now lapsed).

Going forward, the simple initiatives that SA Power Networks intends to develop are:

- an increasing demand component in small customer tariffs;
- better signalling of 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.

The strategy to move toward this more cost reflective pricing, and the metering and customer engagement required to support such pricing, is described further in Chapter 14 of this Proposal.

29.5.2
Assigning customers to tariff classes and to tariffs

The NER set out the mandatory requirements for assigning customers to tariff classes. Rule 6.18.4 requires that customers should be assigned to a tariff class based on one or more of:

- the nature and extent of their usage;
- the nature of their network connection; and
- whether suitable metering is available as a result of regulatory requirements.

Customers with similar connection and usage profiles should be treated equally, with customers having micro-generation facilities treated no less favourably than other customers without micro generation but with a similar usage profile.

The rule also requires that any decision to assign a customer to a particular tariff class or to reassign a customer from one tariff class to another should be subject to an effective system of assessment and review. For example, customers who reduce their demand should be reassigned on the basis of the new load characteristics.

29.5.3
New tariff designs for the 2015–20 RCP

Residential customers

Currently, residential customers have a choice of tariff between an inclining 2-block energy tariff and a monthly demand tariff. There is also an optional controlled load tariff (see later discussion).

We propose to:

- retain the choice of tariff for existing customers, so they can choose which tariff they prefer;
- revise the 2-block energy tariff, with slightly higher fixed charges and lower second block charges likely;
- from 1 July 2017 require new customers and customers who alter their supply arrangements to utilise the monthly demand tariff; and
- develop an alternative to the monthly demand tariff that will be suitable to lower socio-economic households. This tariff will incorporate the same LRMC cost signals as the monthly demand tariff, but will have lower prices in the other tariff elements. This should ensure economically efficient and socially responsible outcomes from the new cost-reflective tariffs.

We expect that the monthly demand tariff will provide good pricing signals for those customers investing in solar PV, battery storage and electric vehicles and in ensuring air-conditioning is efficiently designed in new homes and major alterations.

For controlled load (hot water), we propose to develop new options aimed at shifting load away from the current 11:00 pm demand spike and flattening the off-peak profile. More particularly, we propose to encourage hot water loads to move to the time of lowest demand on the residential network when PV output is at its highest. This will involve new tariff offerings, and may involve discussions on market energy pricing for hot water controlled load profile customers. In particular, we propose to develop optional tariffs aimed at:

- heat pumps, encouraging less energy use during higher daytime temperatures, still being under SA Power Networks' control and not contributing to network peak demands;
- under-floor heating with expanded off-peak hours but not contributing to network peaks;
- new time clock arrangements for storage heating; and
- possibly, new dynamic arrangements to control load for those customers with a smart meter.

These arrangements should result in a more efficient network which can receive more renewable energy from customers, whilst in some cases using less energy (eg heat pumps). It will be a challenge for some segments of the energy industry to consider hot water as an efficient day-time load which can also increase the amount of renewable energy able to be received by the current network.

Small business customers (up to 160 MWh pa)
Most small business customers are currently on energy tariffs, either business 2-rate or business single rate. Some customers have elected to use an agreed demand tariff. All new customers and customers altering their supply arrangements since July 2010 and requiring more than 70 kVA in capacity have been assigned to the agreed demand tariff.

Small business customers who were assigned to the agreed demand tariff (for having more than 70 kVA in capacity) will be able to choose from the existing agreed demand tariff or a new (to be developed) business actual monthly demand tariff.

Small business customers who currently have access to energy-only tariffs will continue to have that option, but can also choose from the two cost-reflective tariff options of either an agreed demand tariff, or the proposed new business actual monthly demand tariff. The latter option is more likely to suit small businesses.

The exception to this existing small business customer rule will be where the small customer uses 70 kVA or more in demand. In that situation the customer could be required to use a cost-reflective tariff and will be assigned to either the transition agreed demand tariff (see large customer commentary below) or the business monthly demand tariff. We will review this prior to 2017 when we consider the AEMC pricing rule change.

For those new small businesses and for those small businesses altering supply arrangements, there will be two separate arrangements:

- those business customers requiring multi-phase power will be assigned to a cost-reflective tariff. The default tariff will be the proposed business actual monthly demand tariff, although the customer could elect to use the agreed demand tariff;
- for single phase customers until 30 June 2017, the customer choice includes business 2-rate as well as the cost-reflective demand tariffs; and
- from 1 July 2017, the new/altered supply single phase customers will not have the business 2-rate choice. All new/altered supply business customers will be assigned to a cost-reflective tariff.

Large business customers (160 MWh pa and above)
Most large business customers are currently on agreed demand tariffs. These tariffs are mandated for all customers with a maximum demand of 250 kVA or greater and, since July 2010, for all new customers and customers altering their supply arrangements where they have access to 70 kVA capacity or greater. The tariffs for these customers will continue, although simplifications of the tariff-steps used for demand will be developed.

We propose to amend the demand tariff structures, in particular replacing the minimum demand requirements (eg 70 kVA for agreed LV demand) with a fixed charge. Customers on demand tariffs will pay for the capacity agreed (with agreed demand) or used (with business monthly demand), not the capacity that the tariff nominates. We believe that this will encourage better demand management by all large business customers at times of highest demand on our networks.

We propose to require all large customers to utilise a cost-reflective tariff from 1 July 2015. That will require many businesses to be reassigned from an energy tariff to a cost-reflective tariff at that time. We will work with these large businesses to transition them from energy tariffs to cost-reflective tariffs.

In particular, we will offer three cost-reflective tariff options:

- the annual agreed demand tariff;
- a new business monthly actual demand tariff (to be developed); and
- a transition agreed demand tariff. This will be a hybrid tariff, partly reflecting the energy tariff that these customers have used, and partly the agreed demand tariff. In 2015/16, we propose a weighting of 20% demand tariff and 80% energy tariff, in 2016/17 this weighting would move to 40%/60%, in 2017/18 to 55%/45%, in 2018/19 to 70%/30% and in 2019/20 to 85%/15%. The transition tariff would not carry over into 2020–25 RCP. We propose to prevent customers from facing an annual network charge increase exceeding 20% with this strategy. Customers should also have time to align their behaviour where possible to the better pricing signals and so reduce their costs (and future SA Power Networks network costs).

For those few large customers who do not have an interval meter, we will develop an alternate energy tariff that has a higher fixed charge reflecting the capacity available to the customer and with lower energy rates. We expect that all large customers with Type 6 metering will have arranged an interval meter with their retailer by June 2016, so this is a temporary tariff only. Customers on this tariff can switch to any of the three cost-reflective tariffs once a suitable meter is installed.

29.6

Annual reporting arrangements

29.6.1
Standard Control Services and Alternative Control Services

The annual pricing proposal submitted to the AER for approval in March/April each year will contain information on the final tariff outcomes for the preceding year-end. These will be compared with the actual revenue allowances as adjusted for inflation, service incentive, the annual cost of debt update and any balances carried forward.

SA Power Networks expects that SCS adjustments will have similar arrangements applied to those currently used for the pass-through controls used for transmission (and PV FiT), including the application of interest to any end-of-year balances.

The ACS pricing for metering services was outlined in Section 29.3. We expect that the annual pricing proposal will simply adjust these prices for actual inflation and the annual cost of debt update. We expect that there will need to be other processes developed to incorporate the 'A' factor adjustments in the price cap control formula[277] which might require the inclusion of actual billing quantities and the amount of ACS revenue billed in the preceding period. Alternatively, the approved building blocks may provide an adequate basis for adjustment. This is a matter for further discussion with the AER.

29.6.2
Pass-Throughs — Transmission charges and jurisdictional scheme

The annual pricing proposal will contain information on the actual billing quantities and the final tariff outcomes for the preceding year-end. This will be compared with the actual payments for transmission (and for PV FiT) as adjusted for balances carried forward.

SA Power Networks expects that similar arrangements to those currently used for the pass-through controls used for transmission (and PV FiT) will apply through to 2020, including the application of interest to any end-of-year balances.

277 AER, Final framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015, April 2014, p52–53

Shortened forms

Shortened forms

Shortened forms

2010 determination	the 2010–15 regulatory determination
2015–20 RCP	the 2015–20 Regulatory Control Period
AA1000SES	Stakeholder Engagement Standard
ABS	Australian Bureau of Statistics
ACS	Alternative Control Services
ADMS	Advanced Distibution Management System
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMP	Asset Management Plan
ARR	Annual revenue requirement
AS	Australian Standard
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
bppa	basis points per annum
CAM	Cost Allocation Method
Capex	Capital expenditure
CATI	Computer assisted telephone interviewing
CBD	Central Business District
CBRM	Condition based risk management
CCP2	AER Consumer Challenge Panel sub-panel
CED	Catastrophic event day
CEG	Competition Economists Group
CESS	Capital Efficiency Sharing Scheme
CFS	Country Fire Service
CGF	Corporate Governance Framework
CHED Services	CKI/HEI Electricity Distribution (Services) Pty Ltd
CLAHs	Current limiting arcing horns
CM&LA	Condition Monitoring and Life Assessment Plan
COAGEC	Council of Australian Governments Energy Council
Contestability	Customer choice of electricity supplier
Controlled Load	The DNSP controls the hours in which the supply is made available
CPI	Consumer Price Index
CPMP	Connection Point Management Plan

CRC	Bushfire Cooperative Research Centre
CRM	Customer Relationship Management
Customer contributions	The value of any network augmentations or extensions funded directly by customers
DAPR	Distribution Annual Planning Report
DCS	Direct control services
DDM	Dividend Discount Model
DEA	Data Envelopment Analysis
Demand	Energy consumption at a point in time
DER	Distributed Energy Resource
Distribution Code, Code, EDC	ESCoSA, Electricity Distribution Code EDC
Distribution Network	The assets and service which link energy consumers to the transmission network
DMIA	Demand management innovation allowance
DMIS	The AER's Demand Management Incentive Scheme
DNSP, Distributor, distribution business	Distribution Network Service Provider
DPTI	Department of Planning, Transport and Infrastructure
DRP	Debt Risk Premium
DSP	Demand Side Participation
DSPR	Distribution System Planning Report
EBA	Enterprise Bargaining Agreement
EBSS	The AER's Efficiency Benefit Sharing Scheme
ECC	Energy Consumers' Council
EDC	Electricity Distribution Code
EGWWS	Electricity, Gas, Water, and Waste Services
EISS	Electricity Industry Superannuation Scheme
EMG	Executive Management Group
ENA	Energy Networks Association
EPA	Environmental Protection Agency
ERP	Enterprise Resource Planning System
ESCoSA, the Commission	Essential Services Commission of South Australia
ETC	Estimated Tax Cost
ETC, Transmission Code	ESCoSA's Electricity Transmission Code ET/05
ETCt	Estimated corporate tax costs
EWPs	Elevated work platforms
F&A	Framework and Approach
Feed-in Scheme	South Australia's Solar Feed-In Scheme under the Electricity (Feed-In Scheme–Solar Systems) Amendment Act 2008
FiT, Feed-in tariff	Buy back rate for energy fed back into the distribution network from small photo-voltaic generators under the Feed-in Scheme
FOM	SA Power Networks' Future Operating Model
FRC	Full Retail Competition, Full Retail Contestability
FTE	Full time equivalent
GDP	Gross Domestic Product

GFC	Global Financial Crisis
GFN	Ground fault neutralising technology
GOS, Grade of service	The proportion of customer telephone calls answered within a particular timeframe
GRN	Government radio network
GSLs	Guaranteed service levels
GWh	Gigawatt hours
HBRA	High bushfire risk areas
Huegin	Huegin Consulting
HV, High Voltage	Equipment or supplies at voltages of 11 kV or above
Hz	Hertz
IAP2	International Association of Public Participation
IEEE	Institute of Electrical and Electronics Engineers
ILUA	Indigenous Land Use Agreement
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)
KPI	Key Performance Indicator
kVA, MVA	Kilo-volt amps and Mega-volt amps, units of instantaneous total electrical power demand.
kVAr, MVAr	Kilo-volt amps (reactive) and Mega-volt amps (reactive) units of instantaneous reactive electrical power demand.
kW, MW	Kilo-watts and Mega-watts, units of instantaneous real electrical power demand.
kWh, MWh, GWh	Kilo-watt hours, Mega-watt hours and Giga-watt hours, units of electrical energy consumption
LGA	Local Government Association
LR	Long Rural
LRMC	Long Run Marginal Cost
LV, Low Voltage	Equipment or supply at a voltage of 220 V single phase or 380 V, three phase
MAB	Meter asset base
MAC	Motor Accident Commission
Marginal Cost	The cost of providing a small increment of service
Market Participant	Businesses involved in the electricity industry are referred to as Market or Rules Participants
MC	Metering Coordinator
MED	Major Event Day
MFS	Maloney Field Services
MPM	Metering Pricing Model
MRP	Market Risk Premium
MRV	Maintenance risk value
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
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER, Rules	National Electricity Rules
NERA	NERA Economic Consulting
NERL	National Energy Retail Law
NGR	National Gas Rules
NIEIR	National Institute of Economic and Industry Research
NOC	SA Power Networks' Network Operations Centre
NPV	Net Present Value
NSW	New South Wales
OHS	Occupational Health and Safety
OMS	Outage Management System
Opex	Operating expenditure
OTR	Office of the Technical Regulator
PBST	Powerline Bushfire Safety Taskforce
PLEC	Power Line Environment Committee (South Australia)
PoE	Probability of Exceedance
PPM	Portfolio Project Management
PQ	Power quality
PSC	Power Systems Consulting
PTRM	Post tax revenue model
PV	Photovoltaic
QoS	Quality of Supply
RAB	Regulatory asset base, Regulated asset base
RAGs	Rod Air Gaps
RBA	Reserve Bank of Australia
Repex	Replacement expenditure
RFM	Roll Forward Model
RFP	Request for Proposal
RIN	Regulatory Information Notice
RIT-D	AER's Regulatory Investment Test-Distribution
RMU	Ring main unit
RPP	Revenue and Pricing Principles
Rules, NER	National Electricity Rules
SA	South Australia
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPN	SA Power Networks

SAPN CCP	SA Power Networks' Customer Consultative Panel
SAUR	Shared asset unregulated revenue
SCADA	Supervisory Control And Data Acquisition
SCS	Standard Control Services
SEM	Submission Expenditure Model
Side constraint	A limitation in the maximum price change which may be applied to a tariff component or a tariff class in any year
SKM	Sinclair Knight Merz
SL-CAPM	Sharpe-Lintner Capital Asset Pricing Model
Small Customer	An electricity customer whose actual or estimated energy consumption is less than a threshold level specified in the Rules — currently 160 MWh per annum
SoRI	Statement of Regulatory Intent
SR	Short Rural
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan
SSF	Service Standards Framework
SSIS	Small Scale Incentive Scheme
State Government	The Government of the State of South Australia
STPIS	The AER's Service Target Performance Incentive Scheme
Subtransmission	Equipment or supplies generally at voltage levels of 33 kV or 66kV (South Australia)
Supply Rate, Supply Charge	The fixed daily cost component of a Network price
SWE	Severe weather events
SWER	Single wire earth return
the Foundation	SA Power Networks' Employee Foundation
TNOC	Telecommunications Network Operations Centre
Transmission Network	The assets and service that enable generators to transmit their electrical energy to bulk distribution supply points
Tribunal	Australian Competition Tribunal
TSS	Tariff Structures Statement
TSWs	Trade skilled workers
TUoS	Transmission Use of System charges for the utilisation of the transmission network
URD	Underground residential development
USAIDI	Unplanned System Average Interruption Duration Index
USAIFI	Unplanned System Average Interruption Frequency Index
VBRC	Victorian Bushfire Royal Commission
VCR	Value of customer reliability
VLC	Voluntary Load Control
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap
WH&S	Work health and safety
Willis	Willis Risk Services
WIP	Work in progress
WPI	Wage Price Index

Attachments

Attachments

Attachments to Proposal

1.1	SA Power Networks: Director's Certification and key expenditure assumptions
1.2	SA Power Networks: Reset RIN Cross Reference Table
1.3	SA Power Networks: Confidentiality Claim
4.1	Huegin Consulting: An indication of how SA Power Networks will benchmark against other DNSPs within the National Electricity Market September 2014
5.3	Energeia: Assessment of Future Tariff Scenarios for South Australia July 2014
6.1	ORC International: SA Power Networks Customer Management Model Study — regulatory Summary
6.3	Deloitte: SA Power Networks Stage 1 Stakeholder and Consumer Workshop report
6.4	ESCoSA: SA Power Networks Jurisdictional Service Standards for the 2015–2020 Regulatory Period Final Decision May 2014
6.5	Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
6.6	SA Power Networks: Customer Service Strategy 2014–2020
6.7	Deloitte: SA Power Networks Stage 2 Stakeholder and Consumer Workshop report
6.8	The NTF Group: SAPN Targeted Willingness to Pay Research — Research Findings
6.9	SA Power Networks: Discussion Paper — Directions for Vegetation Management, SA Power Networks long-term plan for managing trees near powerlines March 2014
6.10	SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
7.2	SA Power Networks: Safety, Reliability, Maintenance & Technical Management Plan (Manual 14)
7.3	SA Power Networks: Distribution Annual Planning Report
7.4	SA Power Networks: Distribution System Planning (AMP 1.1.01)
7.5	SA Power Networks' Expenditure Forecasting Methodology
7.6	AER: Final Framework and Approach for SA Power Networks
7.7	SA Power Networks Future Operating Model 2013–2028
9.1	Condition Monitoring and Life Assessment Plan (AMP 3.0.01)
10.1	Bureau of Meteorology (BOM): Climate extremes analysis for South Australian Power Network operations
10.2	CSIRO and Bureau of Meteorology: State of the Climate 2014
11.3a	Willis Risk Services: SA Power Networks Australia Limited Bushfire Modelling December 2013
11.3b	Willis Risk Services: SA Power Networks Australia Limited Bushfire Modelling April 2014
11.7	Powerline Bushfire Safety Taskforce: Final Report September 2011
11.8	Jacobs: Recommended bushfire risk reduction strategies for SA Power Networks
12.1	SA Power Networks: Proposed Connection Policy for 2015–2020
12.5	BIS Shrapnel: Outlook for SA Power Networks' Real External Labour Cost Escalation and Customer Connections Expenditure Forecasts to 2019/20 August 2014
12.6	SA Power Networks: Reconciliation Workbook — AEMO, SAPN sales and demand forecasts
13.1	SA Power Networks: A Smarter Network Strategy 2014–2025
13.2	Power Systems Consulting: Impact of distributed energy resources on quality of supply
14.1	SA Power Networks: Customer (Service) Technology Plan 2014–2024
14.3	SA Power Networks: Tariff and Metering Business Case
16.1	SA Power Networks: Customer Data Quality Plan 2015–2020
16.2	EY: SAPN IT Data Centre Strategy June 2013
16.5	SA Power Networks: Supply Chain Strategy 2015–2020
16.6	SA Power Networks: TalkingPower Customer Engagement Program summary
16.7	SA Power Networks: Strategic Property Plan 2015–2020
17.3	The NTF Group: Service-Price Research Findings
18.1	SA Power Networks: Proposed Negotiating Framework 2015–2020

20.1	SA Power Networks: Network Document Reference Map
20.2	Frontier Economics: Forecasting labour cost escalation rates using EBA outcomes August 2014
20.3	CEG: Materials cost escalation factors: a report for SA Power Networks August 2014
20.4	Jacobs: Nominal Material Cost Escalation Indices Forecast September 2014
20.5	Maloney Field Services: Forecast Site Values SA Power Networks July 2014
20.6	SA Power Networks: Asset Management Plans (Inventory)
20.7	SA Power Networks: Cost Allocation Method (CAM) September 2012
20.9	GHD: SA Power Networks Safety, Reliability, Maintenance and Technical Management Plan 2014 Audit of Compliance
20.10	OTR and ESCoSA: Safety, Reliability, Maintenance and Technical Management Plan 2014 Audit of Compliance SA Power Networks — Letters (17 June 2014; 3 September 2014; 5 September 2014)
20.11	SA Power Networks: Line Inspection Manual (Manual 11)
20.15	SA Power Networks: Pole Replacement Expenditure Justification
20.19	GHD: Unit cost methodology validation
20.26	SA Power Networks: Strategic Fleet Plan 2015–2020
20.27	SA Power Networks: Network Program Deliverability Strategy
20.28	SA Power Networks: IT Document Reference Map
20.29	SA Power Networks: Portfolio view of non-recurrent projects including milestones and dependencies
20.31	KPMG: Independent Prudence and Efficiency Review of the 2015–20 Price Reset Technology Submission
20.32	SA Power Networks: Information Technology Investment Plan 2015–2020
20.34	SA Power Networks: Flexible load strategy
20.35	SA Power Networks: Information Technology Strategy 2014–2020
20.37	Deloitte: CIS and CRM Business Case; and SAPN Review & Summary
20.38	SA Power Networks: Kangaroo Island (AMP 2.1.03)
20.39	SA Power Networks: RIN Reporting Business Case
20.40	SA Power Networks: IT Enterprise Asset Management Business Case
20.42	SA Power Networks: IT Benefits Map
20.43	SA Power Networks: IT Sourcing and Resource Plan
20.44	AER: Repex Model
20.45	SA Power Networks: Bushfire Mitigation Programs Business Case
20.46	SA Power Networks: Undergrounding for Road Safety Business Case
20.47	SA Power Networks: IT PPM Business Case
20.48	SA Power Networks: IT Field Force Mobility Business Case
20.49	Litmus Group: SAPN IT Enterprise Mobility Strategy
20.50	SA Power Networks: Bushfire Mitigation Summary
20.51	SA Power Networks: Expenditure governance procedures
20.62	SA Power Networks: Asset Management Plan 3.1.05 Poles 2014 to 2025
20.63	SA Power Networks: Asset Management Plan 3.1.10 Overhead Conductor 2014 to 2025
20.64	SA Power Networks: Asset Management Plan 3.2.01 Substation Transformers 2014 to 2025
20.65	SA Power Networks: Asset Management Plan 3.2.05 Substation Circuit Breakers 2014 to 2025
20.66	SA Power Networks: Supply Chain Business Case
20.70	SA Power Networks: Installation of Rapid Earth Fault Current Limiting (REFCL)/Ground Fault Neutralising (GFN) Technology Business Case
20.73	SA Power Networks: Capital and operating historical expenditures
20.74	SA Power Networks: CBRM Justification
20.81	AER: Augex Model
21.1	AON: Insurance Premium Forecast Report September 2014
21.2	Incenta: Debt Raising Transaction Costs October 2014
21.4	SA Power Networks: Scale Escalation Model

21.5	SA Power Networks: Utilities Management 2014–2016 Enterprise Bargaining Agreement
21.10	KPMG: Independent analysis of arrangements between SA Power Networks and CHED Services
21.11	SA Power Networks: Submission expenditure models and documentation
21.13	SA Power Networks: Opex Step Changes
21.14	CHED: FRC IT Support Systems Services Agreement
21.15	CHED: Contact Centre Services Agreement
21.21	Government of South Australia: Revised Distribution Licence Fee July 2015 (Letter)
21.24	SA Power Networks: Asset Management Plan 3.4.01 Metering 2014 to 2025
23.8	SA Power Networks: Efficiency Benefit Sharing Scheme (EBSS) calculation schedules (including RIN Compliance Costs)
23.13	SA Power Networks: Proposed adjustment to STPIS targets 2015–20
23.14	SA Power Networks: Proposed amendment to STPIS Guideline
24.2	SA Power Networks: Shared Assets Cost Reduction Method
25.1	SA Power Networks: Roll Forward Models and Support Schedules
25.2	SA Power Networks: Post Tax Revenue Models and documentation
26	WACC ATTACHMENT
	CEG: The new issue premium
	SFG Consulting: Updated estimate of the required return on equity
	SFG Consulting: The required return on equity for regulated gas and electricity network businesses
	SFG Consulting: Equity beta
	SFG Consulting: Cost of equity in the Black Capital Asset Pricing Model
	SFG Consulting: The Fama-French model
	SFG Consulting: Alternative versions of the dividend discount model and the implied cost of equity
	SFG Consulting: An appropriate regulatory estimate of gamma
	SA Power Networks: Derivation of equity raising costs
29.3	SA Power Networks: ACS Metering Tariff Development Methodology
29.4	SA Power Networks: ACS Metering Pricing Model

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