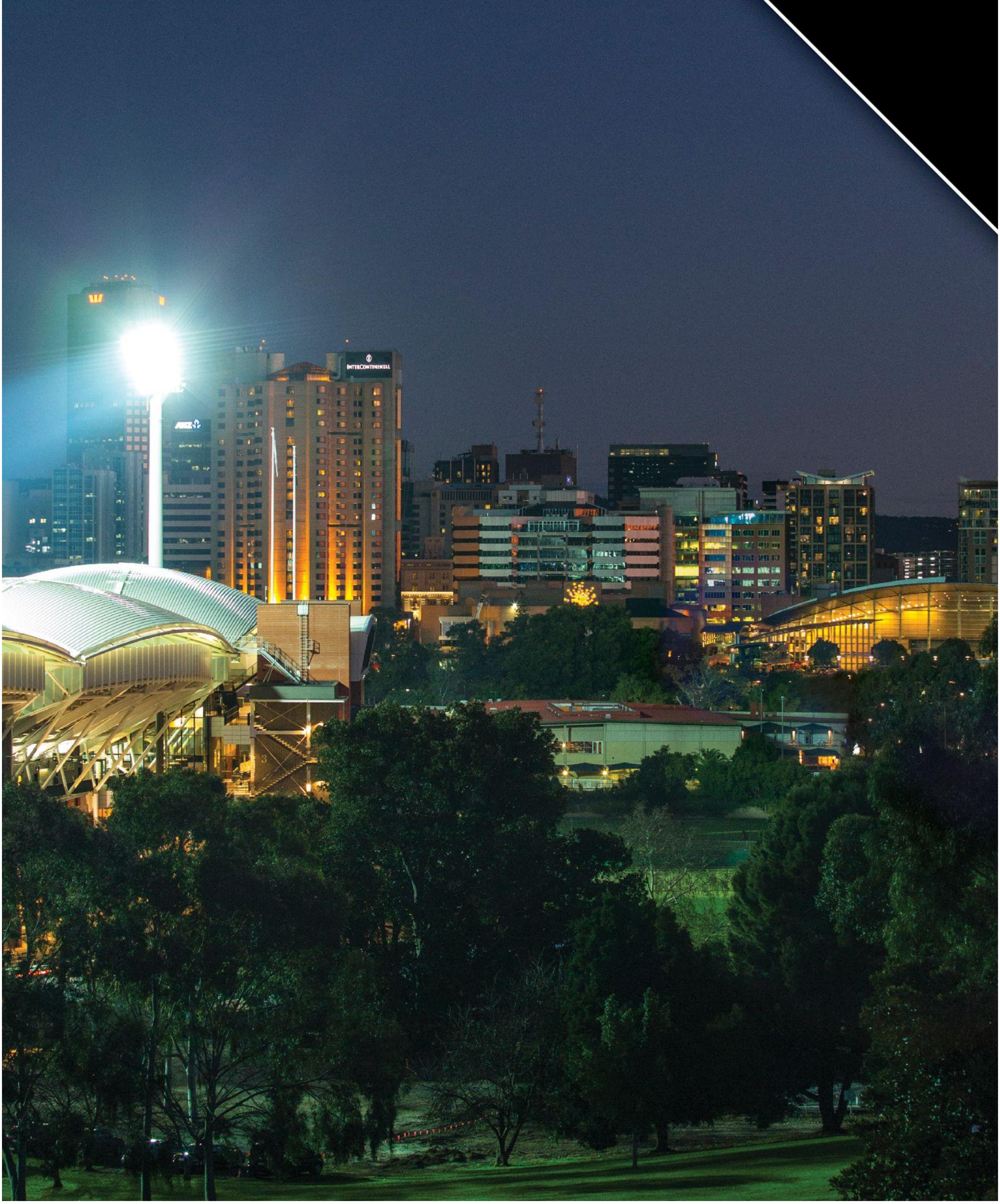
Attachment 21.13

SA Power Networks: Opex Step Changes



SA Power Networks

Operating Expenditure SCS Step Changes 2015-2020

30 October 2014

SA Power Networks
www.sapowernetworks.com.au

Contents

Overview

The purpose of this document is to provide detailed supporting information for each of the step changes outlined in Section 21.6 of the Proposal and in regulatory template 2.17.1 of the Price Reset RIN. This document also specifically addresses the key criteria outlined in the Expenditure Forecast Assessment Guidelines including:

- the key drivers;
- description of incremental forecast expenditure;
- demonstration that expenditure satisfies the operating expenditure objectives and criteria as per NER 6.5.6 (a) and (c) respectively;
- justification for 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.

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 uncontrolled events occur reliance will be placed on the cost pass-through provisions contained in Rule 6.6.1 of the NER. However, if the materiality threshold for pass-through events is not reached, this can result in SA Power Networks incurring expenditures which have not been forecast and for which no allowance has been provided.

We also consider that we will incur increased operating expenditures during 2015-2020 RCP 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. In particular, we have focussed on the manner in which the forecast operating expenditure in relation to each step change is linked to the achievement of the operating expenditure objectives referred to in clause 6.5.6(a)(2) and (4) of the NER. These operating expenditure objectives are the most relevant to the assessment of the forecast operating expenditure for each of the step changes.

It follows that:

- the economic justification for each step change that is set out in this Attachment primarily considers the manner in which the forecast operating expenditure for each step change achieves operating expenditure objective 2 and 4; and

- we have only included additional comments in relation to operating expenditure objective 1 and 3 when that is relevant to the assessment of proposed expenditure (i.e. the activities which are the subject of the relevant expenditure support the meeting and management of the expected demand for standard control services or the maintenance of quality, reliability and security of supply).

Careful attention has also 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 and do not in any way constitute 'more of the same'. In section 21.10 of the Proposal, we have discussed the productivity adjustment factor proposed by the AER in its Expenditure Forecast Assessment Guideline. In particular, we noted that (using the AER's preferred model specification methodology) SA Power Network sits at the efficient frontier and a catch up factor is not applicable. Consequently no individual adjustment is required to SA Power Network's efficient base year cost when determining our forecast operating expenditure.

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 concerns and opinions. Clause 6.5.6(e) of the NER provides that in deciding whether or not the AER is satisfied that our total forecast operating expenditure reasonably reflects the operating expenditure criteria, the AER must have regard to a number of operating expenditure factors. One of the most important operating expenditure factors is the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by SA Power Networks in the course of its engagement with electricity consumers.

As detailed in chapter 6 of our Proposal, our customers and the South Australian community are particularly concerned about safety issues relating to the operation and maintenance of the distribution system. Many of the activities covered by the step changes outlined in this Attachment have been designed not only to achieve the operating expenditure objectives but also to specifically address the safety concerns of electricity consumers as identified during our comprehensive Customer Engagement Program.

Table 1 provides a category summary of the step changes proposed for our 2015-2020 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 (in June 15$) proposed to be included in our 2015-20 operating expenditure allowance.

Table 1: Category summary of step changes and base year adjustments for SCS operating expenditure for 2015-20

June 2015 ($m)	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
New Step Changes						
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 New Step Changes	**35.9**	**42.0**	**48.8**	**46.4**	**43.7**	**216.8**
Base Year Adjustments	(8.4)	(8.6)	(6.8)	(4.6)	(6.4)	**(34.8)**
Total	**27.5**	**33.4**	**42.0**	**41.8**	**37.3**	**182.0**

The step change forecast operating expenditures included in our Proposal (and further explained in this Attachment) have been comprehensively reviewed by the SA Power Networks Executive and approved as efficient and prudent expenditure which:

- reflects the reasonable steps necessary to meet our changing legal and regulatory obligations;
- only includes the incremental costs of complying with those changing legal regulatory obligations;
- delivers on the expectations and addresses the concerns of our customers identified during our extensive Customer Engagement Program; and
- takes appropriate account of the linkages between the proposed capital expenditure program and the related operating costs (both consequential reductions and increases arising from the capital expenditure).

The step changes have been incorporated in our Proposal which has been approved by the Board of SA Power Networks for submission to the AER.

A summary of the proposed step changes and the relevant expenditure objectives / criteria is provided in Table 2.

Table 2: Summary of SCS step changes and objectives / criteria (excl Base Year Adjustments & Debt Raising)

	2015-20 June 15 $m	Legal and regulatory (a)(2)& (4)	Customer driven (a)(1)	Capex related (a)(1)	Service Standards (a)(3)&(4)
Asset inspections	42.1	✓			
Workplace health & safety	12.9	✓			
Energy laws and	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**				

1. Legal and Regulatory Obligations

Introduction

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 good industry practice around asset inspections, maintenance and repair including those arising from community and legal review of industry practice towards mitigating bushfire risks.

In addition, the industry faces in some cases increased operating activity and costs to maintain compliance with existing laws and regulations (i.e. in excess of the historic "average" change in regulatory compliance costs reflected in the 2013/2014 base year operating expenditure as extrapolated over 2015/2020 RCP).

Fundamental to the assessment of step changes related to the legal and regulatory framework is the application of the revenue and pricing principles set out in section 7A(2) of the National Electricity Law. Under the revenue and pricing principles, regulated network service providers must be provided with a reasonable opportunity to recover at least the efficient costs that the operator incurs in providing direct control network services and complying with its regulatory obligations or requirements.

Under section 16 of the National Electricity Law, the AER must take into account the revenue and pricing principles when exercising a discretion in relation to the making of those parts of a distribution determination that are related to direct control network services. A regulatory discretion which takes into account the revenue and pricing principles will contribute to the achievement of the National Electricity Objective.

Our proposed step changes have been designed to contribute to the achievement of the National Electricity Objective by focussing on the promotion of the efficient operation and use of electricity services for the long term interest of consumers of electricity as identified via our comprehensive Customer Engagement Program. In particular, when formulating our step changes we have considered:

- the interests of consumers of electricity over not only the next RCP but also over the next 10 to 15 years; and
- what amounts to the efficient operation and use of electricity services over that longer time frame.

Long term efficiency gains require long term decisions to be made which recognise that it is often more efficient to incur expenditure now in order to reduce expenditure in the future and achieve an overall efficiency gain.

Many of the step changes which are addressed in Section 1 of this Attachment reflect regulatory obligations or requirements that oblige SA Power Networks to take reasonable steps to ensure that certain safety and operational outcomes are achieved.

For example, section 60(1) of the *Electricity Act* provides that SA Power Networks must take reasonable steps to ensure that:

- its infrastructure complies with and is operated in accordance with technical and safety requirements imposed under the Electricity (General) Regulations; and
- its infrastructure is safe and safely operated.

Section 55(1) of the *Electricity Act* provides that SA Power Networks has a duty to take reasonable steps to keep vegetation clear of public power lines in accordance with the principles of vegetation clearance.

Both of these obligations require SA Power Networks to objectively assess what steps a prudent and efficient operator, faced with the same conditions as are currently faced by SA Power Networks (or are likely to be faced by SA Power Networks during the next RCP), would adopt in order to achieve the prescribed regulatory outcomes.

It follows that what amounts to "reasonable steps" at any point in time will depend upon a range of factors such as good industry practice, the available data, consumer and community expectations and the achievement of an appropriate balance between benefit and cost. What amounts to "reasonable steps" today will be different to what amounted to "reasonable steps" 5 years ago and is likely also to differ from what will amount to "reasonable steps" in 5 years' time.

An operator of electricity infrastructure who is exercising the degree of skill, diligence, prudence and foresight that would reasonably be expected from a significant proportion of operators of electricity infrastructure under comparable conditions would, in our view, identify a range of potential options which fall within the boundary of "reasonable steps" and then seek to identify the option which is the most prudent and efficient, addresses the concerns of electricity consumers and best contribute towards the achievement of the long term interest of consumers of electricity.

In this case, the South Australian government (i.e. the body that is responsible for regulating electricity distribution system safety issues) has clearly chosen to adopt a "reasonable steps" formulation for these obligations rather than seek to prescriptively define the steps that must be taken in order to achieve the required regulatory outcome. Under this formulation the operator of the electricity infrastructure is required to continually assess what steps are reasonable taking into account changing industry and community standards.

It follows that the activities which SA Power Networks undertakes in order to discharge these obligations will change over time as good industry practice and community and consumer expectations drive efficient improvement (i.e. whilst the actual wording of the regulatory obligation may stay the same, the scope of the obligation changes over time to reflect good industry practice and the expectations of the consumers and the community).

Operating expenditure objective (4) refers to maintaining the safety of the distribution system through the supply of standard control services. Once again the maintenance of the safety of the distribution system requires the objective determination of the reasonable steps that are required to achieve this objective. This is a dynamic concept and will be informed by good industry practice and applicable industry codes and standards.

This was confirmed by the AEMC when amending the expenditure objectives in 2013, when the AEMC stated that:[1]

> *"the Commission does not consider it appropriate to amend the expenditure objectives for safety. Current levels of safety may appropriately have been influenced by safety standards in voluntary industry codes or Australian standards in addition to regulated standards. It would therefore not be appropriate to limit the expenditure allowance to the regulated standards for safety rather than the current obligation to maintain safety."*

In addition to the above observation, the AEMC noted that operating expenditure objective (4) is to be read broadly, i.e. as applying to issues of safety that are directly or indirectly related to the operation of a distribution network[2]:

> *"A broader definition of safety could include issues that are not directly related to the operation of the … distribution network, i.e. public safety issues, and may include many such things as:*
>
> - *substation fencing;*
> - *power line to ground clearances;*
> - *environmental issues such as the management of transformer oil leaks and audible noise abatement; and*
> - *occupational health and safety (OHS) issues."*

Finally, the AEMC noted that:[3]

> *"There is a risk of inefficiency if the decision of the standard setter is not given effect to in the regulatory process and one standard is used to assess compliance with regulatory obligations but a different standard is used to assess regulatory proposals."*

In this case, the South Australian government (i.e. the standard setter for safety issues) has clearly chosen to adopt a "reasonable steps" formulation for these obligations rather than seek to prescriptively define the steps that must be taken in order to achieve the required regulatory outcome. This approach recognises that the maintenance of safety is a dynamic concept requiring the collection of appropriate data and regular and constant review to ensure that the steps that are proposed to be taken to achieve this objective continue to be reasonable, reflect good industry practice and take into account up to date information concerning risk levels.

The decision of the standard setter in this case must be reflected in and consistently applied during the distribution determination process so as to ensure that the outcomes are efficient and prudent and take into account the revenue and pricing principles (i.e. a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in complying with applicable regulatory obligations or requirements).

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[1] AEMC's Final Rule Determination – National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013, page 10 and 11.

[2] AEMC's Final Rule Determination – National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013, page 19.

[3] AEMC's Final Rule Determination – National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013, page 10.

Summary of proposed step changes

Table 3 provides an overview of the legal and regulatory obligations category of step change and the subsequent sections provide details of the individual step changes.

Table 3: Legal and regulatory SCS step changes 2015-20 RCP

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**

1.1. Asset Inspections

1.1.1 No Access Poles

Reference	
Proposal Section	21.6.1
SEM Category(s)	DA-12 Asset Inspection
Regulatory Driver(s)	Compliance with Legal and Regulatory Obligations
Forecast: 2015-2020 (June 15 $)	$23.4m

Category Function Overview
Asset inspection functions include visual inspections (including Overhead Component Inspections and Ground Component Inspections), patrols of the network, aerial inspections, substation inspections, switchgear inspections and thermographic inspections.

This step change specifically relates to Ground Component Inspections **(GCI).** This type of visual inspection assesses in detail the condition of the poles, footings and guywires, including an assessment of mechanical integrity and the level of corrosion of channels on the pole.

As discussed in the Proposal (at section 9.2), SA Power Networks has embarked on a more structured approach to asset inspection generally involving the prioritised collection of condition based information for asset classes.

It was prudently determined that the inspection of difficult to access assets would be delayed until our new inspection process was introduced and our condition data management had become more mature. Further, it was determined that research should be undertaken into how to tackle this type of inspection and the reparation of these assets before a comprehensive 'no access' asset inspection program was introduced. These assets include ‘no-access poles’ (i.e. poles encased at pavement level with concrete, asphalt and pavers).

These assets have been described as having "hidden failure" risk due to the failure mechanisms not being obvious without a degree of intrusive actions to enable proper inspection.

The new inspection and reparation processes have now been trialled and the inspection program to capture of condition based information on these assets will commence in 2014/15.

Description of the Change
Over the next RCP ensure ‘no-access’ poles are inspected in line with our regulatory obligations, as summarised in the following table.

STRATEGY Description	DRIVERS	FUNDING (ave $M/yr)
Ground line inspection of “no-access” poles	• Public risk [4] • Good industry practice [5] • Alignment with ISO55000 [6] • Enabler for optimisation of asset management investment • Conformance with Safety, Reliability, Maintenance Technical Management Plan (**SRMTMP**) approved by ESCOSA and the electricity distribution licence requirement • Compliance with Electricity Act / Regulations to operate and maintain a safe network.	4.6

The objective of this Strategy is to identify, prudently assess and efficiently ensure that ‘no access’ poles are inspected to achieve compliance with our legal and regulatory obligations.

Limited inspection of pole footings has been undertaken during the current RCP where there are access issues such as bitumen, concrete and paving preventing easy access and cost-prohibitive access methods which require machinery to remove and reinstate the ground covering. Historically the position was that such poles would not be susceptible to the degree of corrosion and degradation of other poles in similar locations. Hence the inspection process did not focus on 'no access' poles.

During 2013/14 we undertook a limited number of ‘no access’ pole inspections in the metropolitan area to assess whether this historical assessment assumption was valid. These inspections have identified that these assets suffer below ground level corrosion and the surrounding surface has not prevented asset deterioration. Accordingly, SA Power Networks needs to expand our inspection program to include all ‘no access’ poles to ensure that we comply with the SRMTMP and our Network Maintenance Manual (No 12) over the 2015-20 RCP.

The Network Maintenance Manual (No 12) is incorporated by reference into the SRMTMP approved by ESCOSA on the recommendation of the SA Office of the Technical Regulator. It details the strategies which govern SA Power Networks' maintenance strategies and specifies the responsibilities associated with those strategies. The manual is designed for use by SA Power Networks employees, from executives to field personnel involved in maintaining the network reliability, safety and security.

[4] Public risk considerations are relevant to our duty under section 60(1) of the Electricity Act and our obligation to comply with our ESCOSA approved the SRMTMP.
[5] Good industry practice informs the steps we must take to discharge our duty under section 60(1) of the Electricity Act and our NER obligations.
[6] Alignment with applicable standards informs the steps we must take to discharge our duty under section 60(1) of the Electricity Act and our NER obligations and in many cases is required in order to comply with our SRMTMP.

We have an obligation to comply with the SRMTMP and the procedures specifically referenced in that plan. As such, we have a legal obligation to comply with the Network Maintenance Manual (No 12).

We have commenced the progressive ramp up of inspections of ‘no access’ poles in 2014/15 and we propose to complete an accelerated program during the first four regulatory years of the 2015-20 RCP, averaging 12,000 poles per annum followed by the sustainable rate of 7,350 poles per annum in the fifth regulatory year and beyond, which will then be consistent with the normal inspection cycle for poles.

Incorporating these assets into the structured condition based inspection program is consistent with PASS - 55 / ISO55000, as obtaining better condition information enables a more detailed assessment of the future performance of the pole. This also enables prudent replacement or replating of the pole, (i.e. poles are only replaced when the risk posed by the failure of the pole becomes greater than the costs of replacing the pole).

What our stakeholders and customers have said to us
Our Customer Engagement Program confirmed that:

- a high level of customer support (88%) for increasing monitoring efforts to monitor the condition of ageing assets and replacing aged assets before they fail;
- a high level of customer support (89%) for upgrading and reinforcing the network where factors such as changing local demand, environment (ie corrosion) and the type of supply to an area (single line of supply) warrant appropriate upgrading and reinforcing; and
- inspecting, maintaining and upgrading the network was ranked in the top 3 community safety and reliability issues by customers in both the workshops and online survey.

Program/Projects required
A program to target 52,000 ‘no access’ poles is proposed over the 2015-2020 RCP with an accelerated program of 12,000 poles per annum in the first four regulatory years followed by the sustainable rate of 7,350 poles per annum in the fifth regulatory year and beyond consistent with the normal inspection cycle for poles.

Timing of the change
As noted above, during 2013/14 we undertook a trial in relation to the inspection of ‘no access’ poles. We have allocated additional expenditure related to the inspection of 'no access' poles in 2014/15 leading into the accelerated inspection program to be undertaken during the 2015-2020 RCP. This timing has been driven by the need to develop and implement an efficient and prudent process for the inspection of 'no access' poles and the integration of that inspection process into our proposed replacement capital expenditure program.

Costing Methodology/Build Up

Through the trial process a cost efficient method for excavating, testing and reinstating 'no access' poles has been developed and commercial tenders sought. Under this approach, multiple teams of ‘Inspectors’ will work in close vicinity with each other, and share resources such as, traffic control, civil contractors, inspection testers, and reinstatement crews e.g. bitumen, paver and concrete crew.

[redacted]

- [redacted]
- [redacted]
- [redacted]

A total of 52,000 poles are estimated to be ‘no access’ poles.

This estimate has been derived using the findings from the inspection of poles in the coastal metropolitan area in 2012. This inspection project found that access prevented adequate condition assessment of 22% of poles of the 71,000 poles inspected. Based on a review of this data, it was conservatively estimated that 18% of the remaining urban poles were ‘no access poles’, that is 18% or 52,000 of the 290,000 urban poles are “No Access” poles.

No double counting of opex (eg output/scale)

As the cost is based on the estimated number of poles not currently inspected and multiplied by a unit rate, the cost is incremental and has not been double-counted. No expenditure (other than the limited trials) has been incurred in the 2013/14 base year inspection costs and this limited expenditure has been taken into account when determining the incremental cost of the full scale inspection process. The costs relate to existing assets only.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14*	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	-	**-**
Materials	N/A	N/A	N/A	N/A	-	**-**
Services	N/A	N/A	N/A	N/A	2.000	**2.000**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**2.000**	**2.000**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

* The 2013/14 trial costs of $0.122m were allocated to capital, so not included in the 2013/14 base year operating expenditure.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services	5.061	5.061	5.061	5.061	3.100	**23.344**
Total	**5.061**	**5.061**	**5.061**	**5.061**	**3.100**	**23.344**

Options Analysis

Option 1 – Business As Usual (Do Nothing)
The BAU approach retains the current approach of inspection for ’hidden failure‘ assets (i.e. no access poles are effectively excluded from the current inspection program).

Continuing with BAU is not recommended.

Under regulatory obligations, SA Power Networks must take reasonable steps to ensure that its distribution network is safe and safely operated. What amounts to reasonable steps will be informed by good industry practice and the increased knowledge we now have of the potential condition of these assets.

We also need to take a proactive approach to identifying and rectifying asset defects in order to discharge our regulatory obligation under the SRMTMP (ie we cannot simply wait for an asset failure to occur where there is risk of injury or death resulting from that asset failure). The first step in this proactive approach is ensuring that we have sufficient information concerning the condition of 'hidden failure' assets.

Our customers have also made it clear through our Customer Engagement Program that they have:

- a high level of concern about community safety throughout South Australia; and
- a preference for asset management, preventative maintenance and strategic investment to drive reliability, manage risk and support economic growth while focusing on public safety.

The ‘do nothing’ option would increase public safety risks as most no-access poles exist in the densely populated metropolitan area. Poles will fail if unsafe levels of corrosion are not detected and remediation of the structure undertaken.

Option 2 – Implement inspections of ‘hidden failure’ assets over 5 years
This option will enable all 'no access' or 'hidden failure' poles that have not been inspected via the structured condition based process to be completed over a 5 year period. This timeframe is based on the outer limit of acceptability of having unknown risks that have high potential public risk consequences (e.g. pole failure in metro area) and is based on the high corrosion zone inspection cycle of 5 year.

STRATEGY Description	DRIVERS	FUNDING (ave $M/yr)
Ground line inspection of “no-access” poles	• Public risk • Good industry practice • Alignment with PASS-55 / ISO55000 • Enabler for optimisation of asset management investment • Conformance with Safety, Reliability, Maintenance Technical Management Plan approved by ESCOSA (SRMTMP) and the electricity distribution licence requirement • Compliance with Electricity Act / Regulations to operate and maintain a safe network.	4.6

The expected benefits of implementing this strategy are as follows:

- SA Power Networks will be able to meet its regulatory obligations under the Electricity Act and the SRMTMP;
- safety risks to the public will be progressively reduced;
- SA Power Networks will avoid reactive emergency response to unplanned failures;
- SA Power Networks will avoid the higher costs of emergency replacement of failed poles relative to planned replacement; and
- SA Power Networks will align with good industry practices and ISO55000 approaches that aim to minimise the life cycle cost of pole assets.

Option 3 – Implement inspections of ‘hidden failure’ assets over 3 years

This option will enable all 'no access' or 'hidden failure' poles that have not been inspected via the structured condition based process to be completed over a 3 year period. This timeframe is based on the maximum rate of resource capability to transition.

STRATEGY Description	DRIVERS	FUNDING (ave $M/yr)
Ground line inspection of “no-access” poles	• Public risk • Good industry practice • Alignment with ISO55000 • Enabler for optimisation of asset management investment • Conformance with SRMTMP and the electricity distribution licence requirement • Compliance with Electricity Act / Regulations to operate and maintain a safe network.	5.4

This option is not recommended due to the higher cost of implementation and the practicality of programming. If all 'no access' poles are inspected in 3 years, then moved to a 5 or 10 year cycle, this would not be considered prudent expenditure planning.

Preferred option

Option 2 is considered the most prudent approach to inspecting the 'hidden failure' assets over a reasonable period of time in line with the highest corrosion zone inspection cycle of 5 years.

Alignment with the NER expenditure objectives & criteria

Our proposed / recommended approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Any failure of a network asset could potentially impact on SA Power Networks' ability to meet or manage expected demand for standard control services.
Comply with all applicable regulatory obligations or requirements	SA Power Networks has a regulatory obligation to take reasonable steps to maintain its network assets in a safe operating condition. What amounts to reasonable steps changes over time and will be informed by good industry practice. The proposed inspection program constitutes a reasonable step, reflects good industry practice and will ensure that the pole defect rectification program is prudent and efficient by providing actual condition data where no condition data has been previously available. In addition, SA Power Networks has a regulatory obligation to comply with its ESCOSA approved SRMTMP and the Network Maintenance Manual (No 12) which is incorporated by reference into the ESCOSA approved SRMTMP. Under the SRMTMP and the Network Maintenance Manual (No 12) we are required to comply with various maintenance strategies including in relation to poles.
Maintain safety of the distribution system	As mentioned above, the main driver for this expenditure is the maintenance of the safety of the distribution system. The maintenance of safety of the distribution system requires an evidenced based assessment of asset condition and associated asset failure risk to ensure that the distribution system is maintained in a safe condition.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our proposed approach of inspecting assets over a 5 year, rather than a 3 year period, represents an efficient approach as it ensures that we can meet our regulatory obligations at the lowest cost. We have already developed and implemented a cost efficient method to excavate, test and reinstate no 'access poles' and commercial tenders have been used to fix the unit costs.

Operating Expenditure Criteria	Considerations
Cost that a prudent operator would require to achieve the objectives	We consider that the proposed inspection program is required for us to appropriately discharge these responsibilities and reflects what a prudent operator would do to meet our legal and regulatory obligations during the 2015-2020 RCP. The asset condition data that will be gathered via this inspection program will enable us to develop prudent and efficient 'no access' pole defect rectification program during the next RCP and beyond. We understand that other DNSPs inspect and reinstate concrete/bitumen /paving when undertaking this type of inspections.
Realistic expectation of demand and cost inputs required to achieve the objectives	We have undertaken a trial of 'no access' pole inspections which has allowed us to understand the likely magnitude of the inspection program for the 2015/2020 RCP and to determine the costs inputs required to achieve prudent and efficient levels of compliance with our regulatory obligations.

Supporting Documentation

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 - SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Supporting Document 20.13 – SA Power Networks: Asset Inspection Strategy Business Case
- Supporting Document 21.37 – Western Power: 2008 Distribution Wood Pole Audit Review and Order

1.1.2 Underground Cable

Reference	
Proposal Section	21.6.1
SEM Category(s)	DA-12 Asset Inspection
Regulatory Driver(s)	Compliance with Legal and Regulatory Obligations (ISO55000 alignment, Advances in Technology)
Forecast: 2015-2020 (June 15 $)	$3.1m

Category Function Overview
Our underground network has historically not been condition monitored as there has been no method of prudently performing this type of inspection. This lack of condition data has resulted in a reactive maintenance regime where cables are fixed when they fail and cable sections replaced following multiple failures. This reactive maintenance regime results in large unplanned customer outages. Without a proactive approach to inspecting and remediating cable faults, the number of such unplanned customer outages is likely to increase above historic levels as the cable networks continue to age and reach end of life. Our Customer Engagement Program has shown that customers want current levels of reliability maintained.

This step change specifically relates to underground cable Inspections.

Description of the Change
Over the next RCP ensure critical underground cables are inspected in line with our regulatory obligations, as summarised in the following table.

STRATEGY Description	DRIVERS	FUNDING (ave $M/yr)
Cable Condition Monitoring Program	• Good industry practice • Alignment with ISO55000 • Enabler for optimisation of asset management investment • Mitigate the expected increasingly adverse effect of cable network ageing on reliability • Compliance with SRMTMP	0.616

Condition assessment of underground cables

Our underground network has historically not been condition monitored, as to date there has been no method of prudently performing this type of inspection. This lack of condition data has resulted in a reactive maintenance regime where cables are fixed when they fail and cable sections replaced following multiple failures. This reactive maintenance regime results in large unplanned customer outages. Without a proactive approach to inspecting and remediating cable faults, the number of such unplanned customer outages is likely to increase above historic levels as the cable networks continue to age and reach end of life. Our Customer Engagement Program has shown that customers would be concerned by that impact.

SA Power Networks recently purchased new cable fault finding technology with the additional capability of determining the condition of underground cables. It is proposed that a new program be started to determine and baseline the condition of 62% of SA Power Networks critical cable sections over the next five year period. SA Power Networks classifies cable criticality as follows:

- Critical – Feeder Exits and CBD cables;
- Very High – Critical Backbone. SA Power Networks has a list of the top 25 most unreliable feeders by customer impact and faults by km over the past 5 years, the backbone cables on these feeders are considered high criticality;
- High – Other Backbone feeders, radial feeds to major customers (eg SA Water Pumping Stations);
- Medium – Where 4 or more gensets would be required in the worst case scenario; and
- Low – All other cable.

It is expected that the program will identify critical cables at significant risk of failure and as a result the number of cable repairs is expected to rise. In the medium term the number of unplanned cable faults will remain at similar levels to historical levels and planned cable repairs will change from 0% of the current cable repairs to around 15%.

The number of cable failures is expected to increase over time as the cables continue to age. Over the longer term, as more complete longitudinal condition information is collected regarding the condition of the underground cables, it is expected that more targeted replacements will be made thereby limiting the increase in the number of cable failures. This is expected to prevent unplanned cable failure costs rising and will assist in maintaining reliability.

There is forecast to be no Service Target Performance Incentive Scheme (STPIS) benefit in the next RCP as a consequence of the introduction of this program. Until sufficient cable sections are tested, a better understanding of the technology and its capabilities is developed, and a sufficient level of planned repairs are undertaken, we would not expect cable faults to reduce.

Incorporating these underground assets into the structured condition based inspection program is consistent with our SRMTMP and ISO55000, as obtaining better condition information enables a more detailed assessment of the future performance of the cables. The information collected will be used to:

- Determine likely imminent failure and drive immediate intervention;
- Create a cable condition baseline against which degradation in the future can be compared and predictions for intervention made; and
- Form basis of future Asset Management Plans and Strategies for underground cables.

What our stakeholders and customers have said to us
Our Customer Engagement Program confirmed that:

- customers clearly understand the need to invest in the network's ongoing reliability to help underpin the South Australian economy;
- stakeholders and customers believe it is important to prioritise preventative maintenance to reduce network risks; and
- 88% of customers surveyed were satisfied with their current level of network reliability and have advised that they want current levels of reliability to be maintained.
-

Program/Projects required
A program to determine the condition of 62% of SA Power Networks critical underground cables is proposed over the 2015-2020 RCP.

Timing of change
The new program, to determine and baseline the condition of SA Power Networks critical cable sections using the new technology will commence in 2015.

Costing Methodology/Build Up
Estimates of the resources required to undertake inspections of critical sections of our underground cables are as follows:

- 2 switching crews
- 1 cable test van crew
- 1 switching writer
- 1 planner / supervisor
- 1 analyst will be used to interpret the data and load the condition data into the SA Power Networks asset management tool SAP

Resources are required for 4 months of the year (during the lowest load months) and have been costed using current labour and vehicle rates and in a manner which is consistent with Chapter 21 of the Proposal.

The condition monitoring program of SA Power Networks critical cable is planned to be fully up and running in 2015/16.

No double counting of opex (eg output/scale)
The cost is based on the resource calculation outlined above. As no underground cable condition monitoring has been undertaken previously, the cost is additional to the base year operating expenditure. There has been no double counting of costs.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	**Actual 2010/11**	**Actual 2011/12**	**Actual 2012/13**	**Actual 2013/14**	**Forecast 2014/15**	**Forecast 2010-15**
Labour	N/A	N/A	N/A	N/A	0.150	**0.150**
Materials	N/A	N/A	N/A	N/A	-	**-**
Services	N/A	N/A	N/A	N/A	0.150	**0.150**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**0.300**	**0.300**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	**Forecast 2015/16**	**Forecast 2016/17**	**Forecast 2017/18**	**Forecast 2018/19**	**Forecast 2019/20**	**Forecast 2015-20**
Labour	0.293	0.293	0.293	0.293	0.293	**1.465**
Materials	-	-	-	-	-	**-**
Services	0.323	0.323	0.323	0.323	0.323	**1.615**
Total	**0.616**	**0.616**	**0.616**	**0.616**	**0.616**	**3.070**

Options Analysis

Option 1 – Business As Usual (Do Nothing)

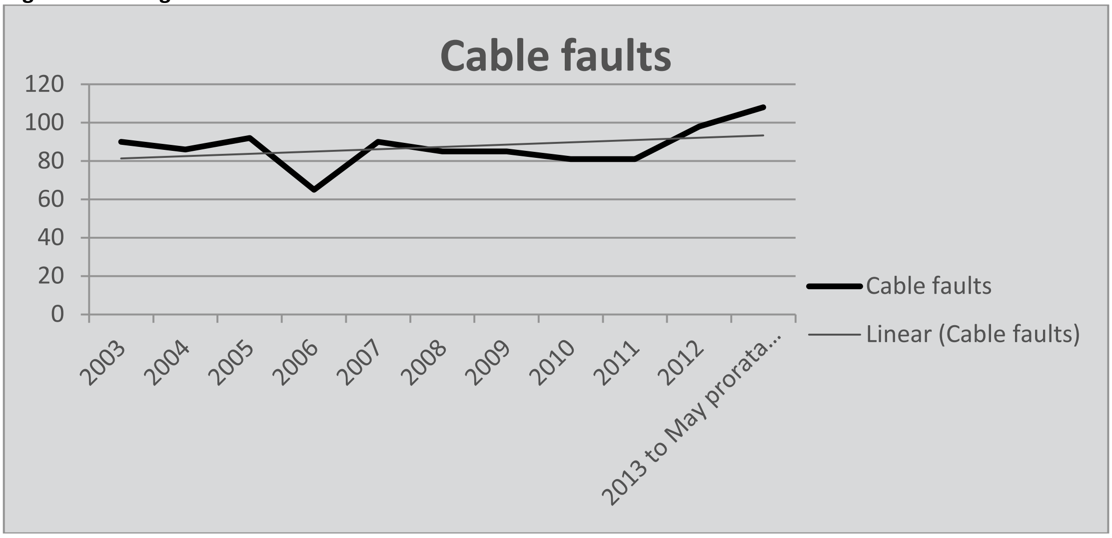
The underground network has historically not been condition monitored. Option 1 would continue this approach.

This was the only option before technology was acquired to enable condition monitoring of underground cables. The business as usual option results in reactive maintenance and potentially sub-optimal cable replacement. Continuing with business as usual is not recommended because it is not considered prudent for SA Power Networks to continue with its current reactive maintenance practices as the cables are ageing and becoming more unreliable.

Other disadvantages:

- Increasing cable failures having an effect on customers.
- SA Power Networks needs to understand the condition of at least the most critical underground cables to make prudent replacement/repair decisions into the future whilst understanding the risks of cable failure.

Figure 1: Underground Cable Faults 2003 to 2013



Option 2 – Implement condition monitoring of 62% of critical cable sections over 5 years

SA Power Networks is at an early stage of its development of an underground cable condition monitoring program. Inspection of 62% of critical cable sections is considered feasible as it will be undertaken during the low load months of the year (4 months). Developing a program that will determine the condition of critical cables in the network is considered to be the first step in the development of a longer term monitoring program.

STRATEGY Description	DRIVERS	FUNDING (ave $M/yr)
Cable Condition Monitoring Program	• Good industry practice • Alignment with ISO55000 • Enabler for optimisation of asset management investment • Mitigate the expected increasingly adverse effect of cable network ageing on reliability • Compliance with SRMTMP	0.616

The expected benefits of implementing this strategy are as follows:

- SA Power Networks will be able to meet its obligations under the SRMTMP;
- SA Power Networks will avoid reactive emergency response to unplanned failures;
- SA Power Networks will avoid the higher costs of emergency replacement of failed cables relative to planned replacement; and
- SA Power Networks will align with good industry practices and ISO55000 approaches that aim to minimise the life cycle cost of cable assets.

Option 3 - Implement condition monitoring of critical cable sections over 5 years
This option would require SA Power Networks to increase expenditure to monitor all critical cable sections during the 2015-20 RCP. This equates to an approximate increase over the Option 2 program of 38% and the cost would increase to $850K per year to achieve the same inspection ratios as option 2.

STRATEGY Description	DRIVERS	FUNDING (ave $M/yr)
Condition assessment of underground cables	• Good industry practice • Alignment with ISO55000 • Enabler for optimisation of asset management investment • Minimise the effect of cable network ageing on reliability • Program focus on most poorly performing asset	0.85

Under Option 3:

- an information rich and comprehensive asset management plan for underground cables could be developed;
- imminent cable faults would be identified and fault intervention could be undertaken in a planned way avoiding potential outages;
- sections of cables with poor condition could be identified thus allowing for the replacement of only the poor condition cables; and
- unreliable feeders can be targeted and deterioration in customer reliability related to those unreliable feeders can be minimised.

However, Option 3 would give rise to a further increase in costs and deliverability issues. The Option 2 program fully utilises the 4 months of lowest load. Therefore, the adoption of Option 3 would move the inspection process into the higher load months thereby causing network access issues.

Option 3 is not recommended due to the higher cost of implementation and the practicality of programming.

Preferred option
Option 2 is considered the most prudent approach to inspecting critical sections of underground cable taking into account both costs and program practicality. Should inspections identify a higher level of rectification work then consideration will be given to increasing the rate of inspection during the next RCP.

Alignment with the NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Any failure of an underground cable could potentially impact on SA Power Networks' ability to meet or manage expected demand for standard control services.
Comply with all applicable regulatory obligations or requirements	SA Power Networks has a number of regulatory obligations to maintain the reliability of supply of standard control services. Any failure of an underground cable could potentially impact on SA Power Networks' ability to maintain the reliability of supply to the required standard. Particularly, given that underground cables are more difficult to access than overhead cables and therefore take longer to repair in the case of failure. SA Power Networks has a regulatory obligation to take reasonable steps to maintain its underground cables in a safe operating condition. What amounts to reasonable steps is informed by good industry practice. The proposed approach constitutes a reasonable step and reflects good industry practice. SA Power Networks has a regulatory obligation to comply with the ESCOSA approved SRMTMP and the Network Maintenance Manual (No 12) which has been incorporated by reference into the ESCOSA approved SRMTMP. Under the SRMTMP and the Network Maintenance Manual (No 12) we are required to comply with various maintenance strategies including in relation to cables.
Maintain safety of the distribution system	Any failure of an underground cable could potentially impact on SA Power Networks' ability to maintain the safety of the distribution system. The maintenance of safety of the distribution system requires an evidenced based assessment of asset condition and associated asset failure risk to ensure that the distribution system is maintained in a safe condition.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our proposed approach to inspecting underground cables reflects efficient costs as it involves only monitoring critical cable sections as opposed to expanding the program to monitor additional high risk but non-critical cables.
Cost that a prudent operator would require to achieve the objectives	By implementing a program to determine the condition of the highest risk sections of the critical underground cables, we will be better able to make prudent decisions and develop prudent and efficient strategies to manage the underground network.
Realistic expectation of demand and cost inputs required to achieve the objectives	Our proposed expenditure is based on detailed calculations of the expected costs required to be incurred using the labour and vehicle rates specified in Chapter 21 of the Proposal.

Supporting Documentation

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 - SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Supporting Document 21.38 – SA Power Networks: Condition Testing of Critical Underground Cables Business Case

1.1.3 Bushfire Inspection (including Thermographic) Frequency

Reference	
Proposal Section	21.6.1
SEM Category(s)	DA-12 Asset Inspection
Regulatory Driver(s)	Compliance with Legal and Regulatory Obligations Change in good industry practice as informed by the VBRC/Bushfire Taskforce informing the duty to take reasonable steps to inspect and clear vegetation. Maintain the safety of the distribution system consistent with good industry practice and community expectations.
Forecast: 2015-2020 (June 15 $)	$15.6m

Category Function Overview
Asset inspection functions include visual inspections, patrols of the network, aerial inspections, substation inspections, switchgear inspections and thermographic inspections.

This step change specifically relates to:

- Visual Inspections which include:
- Overhead Component Inspections (OCI) - These visual inspections (using binoculars) assess in detail the condition of all other components on the pole, including conductors (conductor, fittings, tie wires, joints, services) and overhead equipment (switchgear, transformers, regulators, bushings, fuses, public lighting lamps).
- Ground Component Inspections (GCI) – These visual inspections assess in detail the condition of the poles, footings and guy wires, including an assessment of mechanical integrity and the level of corrosion of channels on the pole.
- Thermographic Inspections – Uses a thermographic camera to detect with thermal imagery, those components that have deteriorated due to a combination of corrosion and high load current to the extent that failure is likely. These inspections are conducted on overhead lines and in substations.

Visual Inspections are typically combined (i.e. they include both OCI and GCI) as a full feeder inspection is undertaken by qualified Asset Inspectors. At SA Power Networks, the current asset inspections cycles have been driven solely by the corrosion zone in which the asset inspection is taking place, which results in either a 5 or 10 year inspection.

Thermographic inspections of overhead power lines can assist in the identification of potential conductor and joint faults. Hot joints can arise in line conductors where a sleeve has been used to connect conductors, or in connections to overhead lines (taps,) lug connections to equipment such as transformers bushings and in switching and protection devices. Thermographic inspections can also identify worn or fatigued components that results in high resistance to power flows and hence local plant heating. Thermographic Inspections are undertaken on the backbone of the feeders and are undertaken on a 5 year cycle in rural areas.

Description of the Change

Over the next RCP to ensure assets in BFRAs are thermographically inspected in line with our regulatory obligations, as summarised in the following table.

STRATEGY Description	DRIVERS	FUNDING (ave $M/yr)
Inspect line assets in BRFA's on a 5 year cycle (including thermographic inspection).	• Public risk (maintain safety of the distribution system) • Good industry practice informing reasonable steps (i.e. Victorian Bushfire Royal Commission) • Enabler for optimisation of asset management investment	3.1

The consumer focus on community safety and the change to good industry practice arising from reviews of major bushfires across Australia have reinforced the need to prudently manage these risks.

Asset inspections provide us with critical information on the condition of assets, enabling decisions to be made regarding their operation, refurbishment and replacement and an informed assessment of the level of associated risk.

At SA Power Networks, the current asset inspections cycles have been driven solely by the corrosion zone in which the relevant assets are located. This results in either a 5 or 10 year inspection cycle. An independent review by Jacobs (formerly SKM) was commissioned by SA Power Networks to review and recommend strategies to reduce the likelihood of fire starts. A key influencing factor in this review was good industry practices and in particular the outcomes of the 2009 Victorian Bushfires Royal Commission. Jacobs recommendations include:

- to reduce the visual inspection cycle from 10 years in all BFRA's to 5 years.
- to maintain the Thermographic inspection cycle at a minimum of 5 years in all BFRA's and extend to include all sections of feeders including LV.

In considering the outcomes of the 2009 Victorian Bushfires Royal Commission, the Jacobs report recommendations and other relevant Australian DNSP practices, SA Power Networks is of the view that implementing a 5 year inspection cycle coupled with the existing annual pre-bushfire patrol is efficient, prudent and consistent with good industry practice and our regulatory obligation to take reasonable steps to inspect and clear vegetation in accordance with the principles of vegetation clearance. This is considered to be effectively equivalent to the maximum 3 year inspection cycle proposed by VBTF.

Approximately 45% of lines will be impacted by this change. This strategy requires an estimated average increase in expenditure of $3.1M per year. This increase in expenditure needs to be assessed against estimated potential consequences of around $500M per event and community expectations concerning the management of this type of risk in light of good industry practice. This constitutes a prudent investment given the level of potential consequences and the communities expectation that SA Power Networks will do everything that is reasonably possible to minimise this risk.

The changes are consistent with the consumer engagement findings that public safety is of high importance.

What our stakeholders and customers have said to us
Our Customer Engagement Program confirmed that:

- customers rated the top 3 community safety and reliability initiatives as:
- inspecting, maintaining and upgrading the network;
- bushfire prevention activities; and
- hardening the network against lightning and storms;
- customers strongly supported initiatives that would result in the prevention of bushfires, safety hazards and provide valued support for the community in emergency situations;
- 90% of customers supported a more reliable power supply to CFS Bushfire Safer Places;
- 90% support SA Power Networks further increasing its inspection, maintenance and construction standards in bushfire risk areas in order to minimise the probability of fires starting from power lines; and
- customers rated building powerlines less prone to fire starts and ensuring bushfire safer places have continuous power supply as the two highest bushfire management initiatives.

Program/Projects required
The proposed step change in visual inspections would result in additional inspection resources being required. It is assumed that this will be contract inspectors plus internal auditing resources.

The proposed step change in thermographic inspections would result in additional inspection resources being required. It is assumed that this will be externally outsourced plus additional internal auditing resources.

Timing of the change
The timing of the change for visual inspections and thermographic inspections is to commence in the 2015/16 regulatory year with all bushfire risk areas to be in a 5 year cycle by the end of the 2015-2020 RCP.

Costing Methodology/Build Up
A comprehensive cost model (‘*Multi-Variable Inspection Forecasting Model*’) for visual inspections has been generated to calculate the costs for future year budgets based on the actual costs to inspect feeders by three contract inspection companies engaged by SA Power Networks (Helistar, Electrix and EPS). The model assumptions:

- The model is based on inspection productivity rates and costs for March 2013-May 2014.
- Additional resources will be trained in 2015 at no cost to SA Power Networks.

The following factors have been taken into account when forecasting inspector effort:

- The urban inspection rate is approximately 3 times longer than rural inspection rate.
- The majority of inspections will continue to be outsourced.
- Introduction of new mobility tools in the future will be productivity neutral.
- The Bushfire Risk Area feeders will be all inspected by the end of the 2015-20 RCP (ie the inspections are spread evenly across the 5 year period).

The inspection costs for thermographic inspections of $450K/annum have been extrapolated using the following assumptions:

- The costs can be uniformly distributed across the annual kilometres of line inspected on a pro rata basis.
- A 50% additional cost for 33kV and 11/7.6kV spurs was included for the BFRAs (as non-backbone kilometre distance is unknown).
- The cost/km was applied to the Low Voltage network for the BFRA.

No double counting of opex (eg output/scale)
The calculation of the step-change has been based on the difference in the 2013/14 inspection costs and the proposed changes in scope and frequency of inspections as detailed above.

For Visual Inspections, the step-change is based on the difference between the model forecast with business as usual and the model forecast with the change in cycle.

For Thermographic Inspections, the step-change is based on the difference between the current annual inspection costs and the re-calculated inspection costs for the BFRA feeders, which include the addition of inspecting Low Voltage and an allowance for inspection of High Voltage spurs (non-backbone part of the feeder).

A 5% allowance was included for both Visual Inspections and Thermographic Inspections for internal auditing as the additional inspection work is to be performed primarily by external resources.

The costs related to the previous inspection regime have been taken into account when determining the incremental costs of implementing the new inspection regime.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	N/A
Materials	N/A	N/A	N/A	N/A	N/A	N/A
Services	N/A	N/A	N/A	N/A	N/A	N/A
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.176	0.189	0.193	0.194	0.192	**0.944**
Materials	-	-	-	-	-	**-**
Services	2.675	2.941	3.009	3.040	3.006	**14.671**
Total	**2.851**	**3.130**	**3.202**	**3.234**	**3.198**	**15.615**

Options Analysis

Option 1 – Business As Usual (Do Nothing)

The BAU approach retains the current inspection regime for assets within BFRAs. Continuing with the current inspection regime is not recommended because it is not consistent with the inspection regimes adopted by other Australian DNSPs faced with similar environmental issues (i.e. bushfire risk areas).

SA Power Networks must take reasonable steps to ensure that its distribution network is safe and safely operated. What amounts to reasonable steps will be informed by good industry practice and community expectations concerning safety in BFRAs. Our customers have made it clear through our Customer Engagement Program that they have:

- a high level of concern about community safety throughout South Australia; and
- a preference for asset management, preventative maintenance and strategic investment to drive reliability, manage risk and support economic growth while focusing on public safety.

This means that we need to take a proactive approach to identifying and rectifying potential asset defects in order to discharge our regulatory obligation (i.e. we cannot simply wait for an asset failure to occur where there is risk of injury or death resulting from that asset failure). The first step in this proactive approach is ensuring that we have sufficient information concerning the condition of our assets in BFRAs.

Option 2 – Introducing a 5 year inspection cycle for assets in bushfire risk areas and extending thermographic inspections in bushfire risk areas

This option would enable SA Power Networks to transition from existing 5-10 year cycle to 5 year cycle with all affected assets in BFRA's being on a 5 year cycle by the end of the next RCP.

STRATEGY Description	DRIVERS	FUNDING (ave $M/yr)
Inspect line assets in BRFA's on a 5 year cycle (including thermographic inspection).	• Public risk (maintain safety of the distribution system) • Compliance with Electricity Act / Regulations to operate and maintain a safe network • Good industry practice (ie Victorian Bushfire Royal Commission) informing reasonable steps • Enabler for optimisation of asset management investment	3.1

At SA Power Networks, the current asset inspections cycles have been driven solely by the corrosion zone in which the relevant assets are located which results in either a 5 or 10 year inspection cycle. An independent review by Jacobs (formerly SKM) was commissioned by SA Power Networks to review and recommend strategies to reduce the likelihood of fire starts. A key influencing factor in this review was current developments with respect to good industry practices and in particular the outcomes of the 2009 Victorian Bushfires Royal Commission. Included in the Jacobs report were the recommendations:

- to reduce the visual inspection cycle from 10 years in all BFRA's to 5 years; and
- to maintain the Thermographic inspection cycle at a minimum of 5 years in all BFRA's and extend to include all sections of feeders including LV.

Approximately 45% of power lines in BFRAs will be impacted by this change. This strategy would require an estimated average increase in expenditure of $3.1M per year. This increase in expenditure needs to be assessed against estimated potential consequences of around $500M per event and community expectations concerning the management of this type of risk in light of good industry practice. This constitutes a prudent investment given the level of potential consequences and the communities' expectation that SA Power Networks will do everything that is reasonably possible to minimise this risk.

The expected benefits of implementing this strategy are as follows:

- cost-effective refurbishment of assets in BFRA's
- Reduce public safety risk exposure
- Alignment with NEO, good industry practices and ISO55000

Option 3 – Introducing a 3 year inspection cycle for assets in bushfire risk areas and extending thermographic inspections in bushfire risk areas

This option would see a transition from the existing 5 – 10 year cycle to a 3 year cycle. This would require a "catch up" component followed by the sustainable expenditure requirement. All affected assets in BFRA's will be subject to a 3 year cycle within 5 years.

STRATEGY Description	DRIVERS	FUNDING (ave $M/yr)
Inspect line assets in BRFA's on a 3 year cycle (including thermographic inspection).	• Public risk (maintain safety of the distribution system) • Good industry practice (ie Victorian Bushfire Royal Commission) informing reasonable steps • Enabler for optimisation of asset management investment	6.8

This option is not recommended as the step-change will result in a significant price impact to customers and will be difficult to implement due to the scale of the step-change versus the current expenditure in this area.

Preferred option

Option 2 is recommended. In considering the outcomes of the 2009 Victorian Bushfires Royal Commission, the Victorian Power line Bushfire Safety Taskforce, the Jacobs report recommendations and other relevant Australian DNSP practices, SA Power Networks is of the view that implementing a 5 year inspection cycle coupled with the existing annual pre-bushfire patrol is efficient, prudent and consistent with good industry practice and our regulatory obligation to take reasonable steps to inspect and clear vegetation in accordance with the principles of vegetation clearance. This is considered to be equivalent to the 3 year inspection cycle proposed by the VBRC and PBSTF.

Alignment with the NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	The occurrence of a bushfire will impact on SA Power Networks' ability to meet or manage expected demand for standard control services.

Operating Expenditure Objectives	Considerations
Comply with all applicable regulatory obligations or requirements	SA Power Networks has a duty is take reasonable steps to ensure that our distribution system is safe and safely operated and to operate and maintain our facilities in accordance with good industry practice and our regulatory obligation to take reasonable steps to inspect and clear vegetation in accordance with the principles of vegetation clearance. These duties require us to have regard to objectively determined standards of safety (i.e. what a reasonable and prudent electricity distribution system operator, faced with the same conditions and circumstances as apply to SAPN, do?). This objectively determined standard of safety changes over time as what constitutes reasonable steps and good industry practice is influenced by industry developments and learnings. We continually monitor these industry developments and learnings to ensure we are discharging this dynamic and evolving responsibility. In our view, implementing a 5 year inspection cycle coupled with the existing annual pre-bushfire patrol is required for us to discharge these responsibilities in a manner which is consistent with current good industry practice and the expectations of the community as identified through our Customer Engagement Program.
Maintain safety of the distribution system	We have a number of duties to maintain the safety of the distribution system and we consider that the adoption of our proposed approach will better ensure that we are able to discharge these duties. The maintenance of the safety of the distribution system requires an evidenced based assessment of asset condition and associated asset failure risk to ensure that the distribution system is maintained in a safe condition.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	We consider that our approach of adopting a 5 year visual inspection cycle rather than the VBRC recommended 3 year cycle (and maintaining the existing annual pre-bushfire patrol) is required for us to appropriately discharge our safety responsibilities. SA Power Networks has also implemented KPIs for the contractor inspectors and will work with the contractor companies to continuously improve productivity and quality.

Operating Expenditure Criteria	Considerations
Cost that a prudent operator would require to achieve the objectives	We are of the view that implementing a 5 year inspection cycle coupled with existing annual pre-bushfire patrol is efficient, prudent and consistent with good industry practice and our regulatory obligation to take reasonable steps to inspect and clear vegetation in accordance with the principles of vegetation clearance. The step change proposed is expected to increase SA Power Networks spend in relation to inspections in BFRA in line with other DNSPs. Visual inspections by other DNSPs are typically undertaken using 2 inspectors. SA Power Networks demonstrates efficiency by using 1 inspector, thus minimising these costs.
Realistic expectation of demand forecast and cost inputs required to achieve the objectives	A cost analysis based on 2013/2014 productivity and contractor inspector rates has been undertaken to ensure that our forecasts and inputs are realistic. In addition, inspectors undertaking visual inspections are trained and accredited inspectors.

Precedent from previous decisions or evidence from other DNSPs

Bushfire risk is the most significant public risk issue for SA Power Networks to manage given the very high potential safety and economic consequences. Based on potential consequences of a single bushfire event of around $500M, this consequence is categorised as Catastrophic using the SA Power Networks risk management framework and therefore the mitigation strategy is to manage the likelihood to as low as reasonably practical (ALARP) in a manner that is consistent with well-established industry risk management principles.

Following the Victorian bushfires of 2009, a Royal Commission was established to conduct a wide ranging and comprehensive review and produce recommendations to prevent another future tragic event. In particular, Recommendation 28 was:

> *"The State (through Energy Safe Victoria) require distribution businesses to change their asset inspection standards and procedures to require that all SWER lines and all 22-kilovolt feeders in areas of high bushfire risk are inspected at least every three years."*

Note: The Victorian “areas of high bushfire risk” are equivalent to the South Australian MBFRA (Medium Bushfire Risk Area) and HBFRA (High Bushfire Risk Area) combined.

In Victoria, legislation was passed requiring this recommendation to be met by electricity network owners. Further, SP AusNet and Powercor (two of the distributors that have bushfire risk exposure) have changed their inspection regime to 2.5 years. These distributors also submitted the consequential cost increase as a cost pass through event to the AER which (although obliged to accept the Victorian jurisdiction 3 year inspection requirement as a cost driver) accepted the increased standard of 2.5 years as prudent and efficient.

Set out below is our understanding concerning the comparative bushfire risk area inspection practices of other DNSPs':

Distributor	State	BFRA Overhead assets Inspection cycle frequency	Source
Powercor	Victoria	2.5 years	AER Cost pass through determination
SP AusNet	Victoria	2.5 years	AER Cost pass through determination
Aurora	Tasmania	3.5 years	Response to VBRC
Essential Energy	New South Wales	4 years	Chap 4 Network Management Plan - Sep 2013
Endeavour Energy	New South Wales	4 years	Jacobs (SKM) Report
Ausgrid	New South Wales	5 years (+2.5 years) [1]	Chap 4 Network Management Plan - June 2014
Western Power	Western Australia	4 years [2]	Peer contact

[1] Detailed overhead power line inspections every five years with intermediate two and a half yearly ground line pole inspections and treatment.

[2] 3 year cycle currently being considered.

Supporting Documentation

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 - SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Attachment 11.8 - Jacobs: Recommended bushfire risk reduction strategies for SA Power Networks
- Supporting Document 20.13 - SA Power Networks: Asset Inspection Strategy Business Case
- Supporting Document 21.40 - SA Power Networks: Multi-variable Inspection Forecasting Model

1.2. Workplace Health & Safety

1.2.1 Asset Inspection – 2 Person Crews

Reference	
Proposal Section	21.6.1
SEM Category(s)	DA-12 Asset Inspection
Regulatory Driver(s)	Compliance with Legal and Regulatory Obligations
Forecast: 2015-2020 (June 15 $)	$2.8m

Category Function Overview
Asset inspection functions include visual inspections, patrols of the network, aerial inspections, substation inspections, switchgear inspections and thermographic inspections.

This step change specifically relates to Patrols.

A Patrol means a visual review from a vehicle of overhead distribution assets with the intention of identifying obvious defects. Whereas an inspection is a detailed visual inspection of all assets requiring a stop at structure, detailed examination of ground level components (e.g. pole corrosion) and detailed visual observation (aided or unaided) of overhead components. Patrols can be undertaken from the ground or air. For this step change the focus is on patrols performed using motor vehicles.

Description of the Change
Pre-bushfire season patrols have in the past been performed by a single person in a light vehicle. A recent review of the safety risk assessment associated with these patrols has identified that despite job safe work procedures requiring the individual to stop the vehicle before inspecting the asset, the human behaviour element and the timeframe to complete the patrols before fire danger season commencement, means that inspections have been done 'on the run' while the vehicle is moving.

The requirements of sections 17 and 19 of the *Work Health and Safety Act 2012* (SA) (**WHS Act**) necessitate a shift to 2 person inspection crews that will commence and be fully operational from 2015/16.

The harmonised WHS Act commenced on 1 January 2013 after an extensive period of consultation. The WHS Act, along with the Work Health Safety Regulations and Codes of Practice, provide a framework to protect the health, safety and welfare of all workers at work and of other people who might be affected by the work.

The guiding principle of the WHS Act is that all people are to be given the highest level of health and safety protection from hazards arising from work, so far as reasonably practicable. In particular, section 19 of the WHS Act requires SA Power Networks, as a person carrying on a business, to ensure, so far as is reasonably practicable, the health and safety of its workers while at work.

Importantly, the WHS Act definition of 'workplace' extends to any place where a worker goes or is likely to be, while at work. That includes vehicles. 'Worker' includes any person who carries out work for SA Power Networks, including employees, contractors, apprentices and a range of others.

In addition, section 17 of the WHS Act provides that this duty requires SA Power Networks to eliminate the risks to health and safety, so far as is reasonably practicable, and if it is not reasonably practicable to do so, to minimise those risks as far as is reasonably practicable.

The term 'reasonably practicable' means what could reasonably be done at a particular time to ensure health and safety measures are in place. In other words, what can reasonably be done will change over time. In determining what is reasonably practicable, SA Power Networks is required to weigh up all relevant matters prescribed by the WHS Act but cost may only be considered after assessing the extent of the risk and the available ways of eliminating or minimising the risk.

Further, cost will not be a key factor in determining what is reasonably practicable unless it can be shown to be 'grossly disproportionate' to the risk.

This step change has been guided by and reflects these regulatory principles and requirements.

STRATEGY Description	DRIVERS	FUNDING (ave $M/yr)
Move from single person patrol to two person patrol for planned patrols	• Employee and public WH&S risk • Increased focus on road safety risk prevention • Compliance with legal and regulatory obligations • Maintaining broader public safety issues associated with the distribution system[7]	0.6

Program/Projects required
The requirement for two-person patrols will be included in the 2015 scope for pre-bushfire patrols.

Timing of the change
This change will commence in May 2014 for the 2015/16 pre-bushfire patrols.

Costing Methodology/Build Up
An estimate of the costs has been prepared on the basis of:

- Inclusion of Living Away From Home Allowance;
- Low qualification driver;
- Historical effort to perform the patrols;
- Slight reduction in patrol times; and
- Slight increase in defect detection.

[7] As per the AEMC's comments on page 19 of the Final Rule Determination – National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013.

[redacted]

No double counting of opex (eg output/scale)
As the step change cost is for an additional low-qualification driver, this is an incremental step-change in costs. As the two-person patrol program has not commenced, it has not been included in the base year operating expenditure. The forecast step change will start commence in 2014/15 and be fully operational in 2015/16 for the pre-bushfire patrols for summer.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	-	**-**
Materials	N/A	N/A	N/A	N/A	-	**-**
Services	N/A	N/A	N/A	N/A	0.227	**0.227**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**0.227**	**0.227**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services	0.569	0.569	0.569	0.569	0.569	**2.845**
Total	**0.569**	**0.569**	**0.569**	**0.569**	**0.569**	**2.845**

Options Analysis

Option 1 – Business As Usual (Do Nothing)

SA Power Networks' employees travel in excess of 18 million kilometres per annum. During 2013 and 2014 we experienced an increase in motor vehicle incidents. As a result, we have undertaken a comprehensive review to eliminate or minimise so far as is reasonably practicable all potential safety risks during travel.

The BAU option does not implement the change from single person to 2 person pre bushfire season patrols. Adoption of this BAU option would be inconsistent with the current business employee safety strategies in particular around driver safety.

Continuing with BAU is not recommended because the risk of exposing a driver and other road users to a vehicle accident increases dramatically when the driver is looking away from the road. As previously mentioned, the WHS Act imposes duties on SA Power Networks to eliminate or minimise this health and safety risk so far as reasonably practicable. This is an objectively determined safety standard which will change over time to reflect good industry practice and available data.

Option 2 – Two-Person Patrols for Planned Patrols

This option involves moving from a single person crew to two person crew to undertake pre bushfire season patrols commencing prior to 2015/16 bushfire season.

STRATEGY Description	DRIVERS	FUNDING (ave $M/yr)
Move from single person patrol to two person patrol for planned patrols	• Employee and public WH&S risk • Increased focus on road safety risk prevention • Compliance with legal and regulatory obligations • Maintaining broader public safety issues associated with the distribution system	0.6

Following SA Power Networks review of all risks associated with employees driving (in view of the 18 million kms travelled each year) it was identified that the single person crew undertaking pre bushfire season patrols was not commensurate with our safety obligations under sections 17 and 19 of the WHS Act. A shift to 2 person inspection crews is necessary to eliminate or minimise risks to the safety of those inspection crews and the general public so far as is reasonably practicable.

This option reflects good industry practice and the available data concerning the safety and effectiveness of our existing inspection procedures. While there is a cost increase arising from this option we consider the implementation of 2 person crews:

- Will improve the performance of both driving and identifying feeder faults
- Will Improve safety by reducing potential for injury and harm to our employees and the public; and
- Will demonstrate that reasonable steps are being taken to comply with the WHS Act.

Preferred option

Option 2 is considered the most prudent approach to undertaking pre-bushfire season patrols.

Alignment with the NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Prudent and efficient power line patrols support our ability to meet and manage demand for SCS.
Comply with all applicable regulatory obligations or requirements	Recent safety risk assessments have identified that the requirements of sections 17 and 19 of the WHS Act necessitate a shift to 2 person inspection crews to ensure that SA Power Networks is eliminating or minimising risks to the safety of those inspection crews and the general public so far as is reasonably practicable. This reflects good industry practice and the available data concerning the safety and effectiveness of our existing inspection procedures. We consider that our proposal is required for us to appropriately discharge our regulated safety responsibilities to both our employees and the general public.
Maintain safety of the distribution system	Prudent and efficient power line patrols support our ability to maintain the safety of the distribution system taking into account the broader public safety issues associated with the operation of the distribution system8.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach involves employing unskilled drivers for pre-bushfire patrols which minimises the costs associated with this step change. SA Power Networks has also implemented KPIs for contractor inspectors and works with the contractor companies to continuously improve productivity, quality and safety.
Cost that a prudent operator would require to achieve the objectives	We consider that our approach to changing from single person to two person pre bushfire season patrols prior to the 2015/16 bushfire season is consistent with what a prudent operator would do to comply with SA Power Networks' regulated safety obligations.

[8] As per the AEMC's comments on page 19 of the Final Rule Determination – National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013.

Operating Expenditure Criteria	Considerations
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed expected scope of this activity and the resources required to efficiently and prudently achieve the related objective. Cost inputs have been determined in accordance with the process outlined in Chapter 21 of the Proposal.

Supporting Documentation

- Supporting Document 20.13 – SA Power Networks: Asset Inspection Strategy Business Case

1.2.2 Network Operations

Reference	
Proposal Section	21.6.1
SEM Category(s)	DA-2 Network Access, Monitoring and Control
Regulatory Driver(s)	Compliance with Legal and Regulatory Obligations relating to safety
Forecast: 2015-2020 (June 15 $)	$4.0m

Category Function Overview
The Network Operations Centre (**NOC**) monitors and manages our high voltage network in real time, and controls safe access to our distribution system for people who need to work on the distribution system.

Description of the Change
Ensuring sufficient resources are available to undertake NOC activities safely and efficiently is extremely important. During the current RCP we have seen an increase in the number of third party connections and embedded generation connections and this is forecast to significantly increase during the next RCP. The level of activity and responsibility within the NOC will also be increased by the proposed investment in equipment to enable the effective monitoring of the low voltage network which will enable customers to implement more distributed technologies.

This will necessitate an increase in number of resources who operate the NOC outside normal business hours. Additional resources will also be required to manage telephone calls, to prepare, manage and update operational interface protocols with third parties and to manage the volume of procedures and work instruction used by the NOC.

What stakeholders and Customer have said
Our customers stressed the importance of community safety throughout our Customer Engagement Program. This step change relates directly to public and employee safety. The specific initiative was not directly raised through the CEP.

Programs/ Projects required
Recruit sufficient additional resources to meet the growth in activity to be undertaken and managed in the NOC recognising that there is a substantial lead time to train and accredit NOC operators.

Timing of change
The required resources will be recruited during 2014/15.

Costing Methodology/Build Up

The incremental cost is associated with the appointment of labour resources to positions within the NOC. This includes 4.2 Distribution Network Controllers (Grade 8); 1 Call Management Control (Grade 8) and 1 Document Control (Grade 8). These resources will be recruited during 2014/15. This is considered the minimum required expenditure to meet our overarching duty to eliminate or minimise, so far as is reasonable practicable, the health and safety risks to our workers[9] and to maintain the safety of the distribution system.

No double counting (eg output/scale)

These resources will be additional to current staffing levels to meet a step change in the level of operations occurring in the NOC, particularly outside normal business hours, which is arising from a step change in the way the network is moving towards a two way network and is not related to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	0.400	**0.400**
Materials	N/A	N/A	N/A	N/A	-	**-**
Services	N/A	N/A	N/A	N/A	**-**	**-**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**0.400**	**0.400**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.789	0.789	0.789	0.789	0.789	**3.945**
Materials	-	-	-	-	-	**-**
Services	-	-	-	-	-	**-**
Total	**0.789**	**0.789**	**0.789**	**0.789**	**0.789**	**3.945**

Options Analysis

The two options that are available are to incrementally increase current resource levels consistent with the output growth of our business (**option 1**) or to engage sufficient resources to meet the step change in activity in the NOC which is reflective of the changing operation of the network and the proposed significant increase in embedded generation and LV monitoring above current levels (**option 2**).

[9] See sections 17 and 19 of the WHS Act.

Option 1 is expected to give rise to an increasing potential for operational errors to occur in the NOC. Given the high risk work undertaken in the NOC, operational errors can result in physical harm to staff and members of the public, and the risk of fatality through electrocution. Allowing a high risk – high consequence environment to occur where increasing errors could occur is not consistent with our overarching duties in regards to public safety and the health and safety of our employees.

As discussed, with increasing demand side solutions, such as DNSP operated embedded generation, there is an increasing demand for constant and vigilant monitoring of the distribution system. This critical network monitoring function performed by the NOC can no longer afford to be undertaken by a single operator outside normal business hours (as currently is the case). To comply with regulated Health and Safety requirements we must be able to manage fatigue, provide regular meal and rest breaks, and have appropriate contingencies in the event of sudden or unexpected illness of duty operators.

On this basis the increased operational expenditure detailed herein, represents the minimum required expenditure to meet our regulated health and safety requirements and to maintain the safety of the distribution system. A second operator is required in order to adequately manage the risks associated with 24 hour operation of the NOC and to meet health, safety and welfare standards for existing staff members. There is a full time equivalent of 4.2 NOC shift controllers required to resource this additional role. This is in line with fatigue risk management methodology.

Further, a Call Management Control officer (Grade 8) and Document Control officer (Grade 8) are also required to enable management of telephone calls, to prepare, manage and update operational interface protocols with third parties and to manage the volume of procedures and work instruction used by the NOC.

Preferred Option

Option 2 is considered necessary to address the step change in NOC activity consistent with our legal and regulatory obligations.

Alignment with NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand	Prudent and efficient staffing of the NOC supports our ability to meet and manage demand for SCS.
Comply with all applicable regulatory obligations or requirements	SA Power Networks is required to meet various regulated health, safety and welfare standards in relation to its employees, including the overarching duty to eliminate or minimise, so far as is reasonable practicable, the health and safety risks to our workers.
Maintain safety of the distribution system	Prudent and efficient staffing of the NOC supports our ability to maintain the safety of the distribution system.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	We have identified the minimum additional resources required to achieve the relevant objective.
Cost that a prudent operator would require to achieve the objectives	We have identified that a prudent operator would require the additional resources to ensure that the NOC is operated safely and efficiently and in accordance with applicable regulatory obligations and requirements and good industry practice.
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the related objective. Cost inputs have been determined in accordance with the process outlined in Chapter 21 of the Proposal.

Supporting Documentation

- Supporting Document 21.41 - SA Power Networks: Review of Network Operations Centre (NOC) Resources

1.2.3 Fleet Monitoring

Reference	
Proposal Section	21.6.1
SEM Category(s)	A-26 OHS
Regulatory Driver(s)	Compliance with Legal and Regulatory Obligations
Forecast: 2015-2020 (June 15 $)	$2.2m

Category Function Overview
Undertake an appropriate level of diligence over the use of SA Power Networks heavy and light vehicles to ensure the safety of our employees and to enable reasonable steps to be taken to comply with various health and safety and road traffic legislation.

Description of the Change
SA Power Networks workforce is becoming increasingly more mobile in response to changing distribution system conditions and work practices and customer expectations. Our employees currently travel in excess of 18 million kilometres per annum in a range of heavy and light vehicles in various environments including remote and risky areas.

The WHS Act, along with the WHS Regulations and Codes of Practice, provide a framework to protect the health, safety and welfare of all workers at work and of other people who might be affected by the work.

The guiding principle of the WHS Act is that all people are to be given the highest level of health and safety protection from hazards arising from work, so far as reasonably practicable. In particular, section 19 of the WHS Act requires SA Power Networks, as a person carrying on a business, to ensure, so far as is reasonably practicable, the health and safety of its workers while at work.

Importantly, the WHS Act definition of 'workplace' extends to any place where a worker goes or is likely to be, while at work. That includes vehicles.

In addition, section 17 of the WHS Act provides that this duty requires SA Power Networks to eliminate the risks to health and safety, so far as is reasonably practicable, and if it is not reasonably practicable to do so, to minimise those risks as far as is reasonably practicable.

The term 'reasonably practicable' means what could reasonably be done at a particular time to ensure health and safety measures are in place. In other words, what can reasonably be done will change over time. In determining what is reasonably practicable, SA Power Networks is required to weigh up all relevant matters prescribed by the WHS Act but cost may only be considered after assessing the extent of the risk and the available ways of eliminating or minimising the risk.

Further, cost will not be a key factor in determining what is reasonably practicable unless it can be shown to be 'grossly disproportionate' to the risk.
Accordingly, SA Power Networks needs the ability to effectively manage and ensure compliance with this overarching safety obligation. This will also have the ancillary benefit of improving the organisations approach to employee welfare, driving behaviour and risk management.

The introduction of an In-Vehicle Management System will assist in SA Power Networks managing its legislative safety obligations in:

- the WHS Act and Regulations; and
- Road Transport Compliance and Enforcement.

Use of an In-Vehicle Management System will also assist in complying with other obligations, such as:

- Employee Safety and Welfare for mobile employees working alone in remote or risky areas; and
- Measuring driver behaviour and vehicle treatment.

What stakeholders and Customer have said
Customers through our customer engagement program have expressed strong support for investments relating to safety particularly in regards to bushfire and road safety risks. This specific item was not raised during consultation.

Programs/ Projects required
This project proposes to install the In-Vehicle Management System in the entire SA Power Networks fleet and implementing the related business processes and protocols. The system allows for the transfer of data (including alerts) from a mobile employee, to a central location or other mobile device.

Timing of change
Following an initial trial the first stage of the roll out is planned for 2014/15 which will involve:

- The installation of the In-Vehicle Management system in 100 vehicles identified as priority, and related reporting.
- The design and implementation of associated business processes and protocols.
- Training.

The remainder of the fleet will have the IVMS system progressively in the early part of the next RCP.

Costing Methodology/Build Up
Operating expenditure uplift is required to reflect the ongoing monitoring costs associated with these units across SA Power Networks' entire Fleet, and is based on:

- [redacted] and
- A full time person is required for administering, training of SA Power Networks personnel, the reporting structure to Management and the ongoing auditing maintaining of the system, costed at internal labour rates.

A number of suppliers of In Vehicle Management Systems have been trialled since 2011, with Auspace being the chosen supplier after conducting trials with three other suppliers. Costs are considered prudent as commercial negotiations have seen savings of 11.5% on capex purchases with operating costs associated with satellite charges included in the per vehicle cost.

No double counting (eg output/scale)
Whilst we have commenced investment in the IVMS for the first 100 vehicles the step change operating costs are the additional operating costs for the remainder of the existing SA vehicle fleet, i.e. in addition to the costs that have been incurred in the base year of 2013/14.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	-	**-**
Materials	N/A	N/A	N/A	N/A	-	**-**
Services	N/A	N/A	N/A	N/A	0.080	**0.080**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**0.080**	**0.080**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.000	0.062	0.062	0.062	0.062	**0.248**
Materials	-	-	-	-	-	**-**
Services	0.062	0.283	0.480	0.577	0.577	**1.979**
Total	**0.062**	**0.345**	**0.542**	**0.639**	**0.639**	**2.227**

Options Analysis

Option 1 – Business as Usual (Do Nothing)
SA Power Networks' Executive has placed a significant focus on addressing all potential safety risks for our employees. The clear ambition is that all employees go home safe and suffer zero harm at work. During 2013/14 a number of significant vehicle incidents involving SA Power Network employees occurred which had the potential to cause serious injury or potential fatality. During 2013 and 2014 significant management and leader attention has focussed on enhancing our organisations awareness of the risks while driving and the need to drive to the conditions.

Notwithstanding these efforts it is considered that not undertaking all available options to eliminate or minimise the risk to our employees where it is reasonable practicable to do so is not meeting our regulatory obligations and therefore a do nothing option is not acceptable.

Option 2 – Introduction of an In-Vehicle Management System
Option 2 is the preferred option and involves the progressive rollout of the IVMS to all SA Power Networks vehicles. As discussed in Section 20.8.4 of the Proposal and the IVMS business case, the trials undertaken during 2013/14 have demonstrated the value of the IVMS with respect to:

- the maintenance and protection of safety and welfare for mobile employees working alone in remote or risky areas; and
- measuring driver behaviour and vehicle treatment as an input into maintaining broader safety issues relating to the operation of the distribution system.

DNSPs across Australia either are utilising an in vehicle management system or evaluating a system to assist their business in line with their WHS obligations. As such, the use of In Vehicle Management Systems represents good industry practice and what is reasonably practicable to do, both within and outside of the electricity industry, as employers are expected to take responsibility for the provision of a safe work environment for their workers wherever their work is undertaken.

Alignment with NER expenditure objectives & criteria
Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	The introduction of an In-Vehicle Management System will support our ability to meet and manage demand for SCS.
Comply with all applicable regulatory obligations or requirements	SA Power Networks' workforce is becoming increasingly more mobile. The efficient and prudent maintenance and operation of the distribution system is driving the need for this increased mobility. At the same time, SA Power Networks' WHS obligations and compliance requirements are becoming increasingly onerous as what is reasonably practicable and consistent with good industry practice and community concerns changes over time. To continue to effectively manage these regulatory obligations and also improve the organisation's approach to employee welfare, driving behaviour and risk management we consider that it is both efficient and prudent to introduce an In-Vehicle Management System to assist us in: managing and monitoring our the safety and welfare of our mobile employees working alone in remote or risky areas; and measuring driver safety and behaviour and vehicle treatment.
Maintain safety of the distribution system	The introduction of an In-Vehicle Management System will support our ability to maintain the safety of the distribution system. The maintenance of safety of the distribution system requires an evidenced based assessment of risk conditions to ensure that broader safety issues can be appropriately managed.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	We have carefully considered the options for progressively introducing the In Vehicle Management System taking into account that the Communication Hub strategies may be combined with the IVMS during the 2015-2020 RCP. In this way we have identified the option which would be the most efficient if the 2 strategies are combined.
Cost that a prudent operator would require to achieve the objectives	We have formed the considered view that a prudent operator would progressively introduce the IVMS in the manner proposed to ensure that the priority vehicles are fitted with the IVMS and our most at risk employees are the first to benefit from this safety monitoring system.
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the related objective. Cost inputs have been determined in accordance with the process outlined in Chapter 21 of the Proposal and via a competitive selection process.

Supporting Documentation

- Supporting Document 21.20A – SA Power Networks: Fleet business cases, In-vehicle Management System business case
- Auspace IVMS Proposal 1024-M2MQ-103 dated 1 May 2014 (available on request)

1.2.4 Fleet Inspections

Reference	
Proposal Section	21.6.1
SEM Category(s)	A-26 OHS
Regulatory Driver(s)	Compliance with Legal and Regulatory Obligations
Forecast: 2015-2020 (June 15 $)	$3.9m

Category Function Overview

We are required to do what is reasonably practicable to eliminate or minimise health and safety risks to our workers under the WHS Act. This includes conducting fleet inspections of heavy vehicles such as Elevated Working Platforms and Cranes to ensure compliance with the maintenance and inspections requirements detailed in AS 2550.10 (Cranes & Elevated Platforms – Safe Use) and AS 1418.10 (Cranes, Hoists and Winches).

Description of the Change

The WHS Act, along with the WHS Regulations and Codes of Practice, provide a framework to protect the health, safety and welfare of all workers at work and of other people who might be affected by the work.

The guiding principle of the WHS Act is that all people are to be given the highest level of health and safety protection from hazards arising from work, so far as reasonably practicable. In particular, section 19 of the WHS Act requires SA Power Networks, as a person carrying on a business, to ensure, so far as is reasonably practicable, the health and safety of its workers while at work.

In addition, section 17 of the WHS Act provides that this duty requires SA Power Networks to eliminate the risks to health and safety, so far as is reasonably practicable, and if it is not reasonably practicable to do so, to minimise those risks as far as is reasonably practicable.

The term 'reasonably practicable' means what could reasonably be done at a particular time to ensure health and safety measures are in place. In other words, what can reasonably be done will change over time. In determining what is reasonably practicable, SA Power Networks is required to weigh up all relevant matters prescribed by the WHS Act but cost may only be considered after assessing the extent of the risk and the available ways of eliminating or minimising the risk.

Further, cost will not be a key factor in determining what is reasonably practicable unless it can be shown to be 'grossly disproportionate' to the risk.

AS 2550.10 and AS 1418.10 are approved Codes of Practice under the WHS Act. This means that AS 2550.10 and AS 1418.10 are admissible as evidence of whether a duty of care under the WHS Act has been met or not. Having said that, it is recognised that equivalent or better ways of achieving the required work health and safety outcomes may be possible. For that reason compliance with AS 2550.10 and AS 1418.10 is not mandatory <u>provided that</u> any other method used provides an equivalent or higher standard of work health safety than suggested by those Australian Standards.

SA Power Networks is therefore obliged, **at a minimum**; to ensure that the maintenance and inspection of its Elevated Work Platforms and Cranes complies with the maintenance and inspections requirements detailed in AS 2550.10 and AS 1418.10. Fleet inspections provide us with critical information on the condition of vehicles, enabling decisions to be made regarding their operation, refurbishment and replacement.

Following an independent review of our Fleet inspection activities we have identified the need to increase our inspection program to ensure that our fleet remains compliant with the requirements of AS 2550.10 and AS 1418.10. The inspections also assist in complying with other legislative obligations, such as:

- SA Road Traffic Act and Regulations;
- SA Motor Vehicles Act and Regulations; and
- Road Transport Compliance and Enforcement.

What stakeholders and Customer have said
Customers through our Customer Engagement Program have expressed strong support for investments relating to safety particularly in regards to bushfire and road safety risks. This specific item was not raised during consultation.

Programs/ Projects required
In June 2013, SA Power Networks engaged consultants GHD to review our compliance with AS 2550.10 and AS 1418.10 as those Australian Standards relate to the maintenance and inspection of our Cranes and EWP's. In addition, SA Power Networks benchmarked its inspections with manufacturer's recommendations and 3rd party inspection companies and identified that its inspection regime was incomplete when compared to the AS 2550.10 and AS 1418.10.

Timing of change
A trial will be undertaken in a selected depot based on the recommended inspection regime using third party specialist providers in 2014/15 to demonstrate that the proposed improved inspection regime will meet the required standards. Satisfactory completion of this trial will be the basis for adoption for the entire vehicle inspection cycle commencing in 2015/16.

Costing Methodology/Build Up
Cost estimates have been generated, both internally and by independent sources, based on:

- The utilisation of a 3rd party service provider as the lower cost option to ensure full compliance whilst ensuring that SA Power Networks achieves the best value for money price by placing this work in a competitive environment.
- Costs have been based on a proposal presented by Hartrite, the current supplier of these services to Essential Energy.

No double counting (eg output/scale)
The review of the fleet inspection cycle has identified gaps in our current processes. Costs to address those gaps have not been incurred in our 2013/14 base year, and are additional to normal output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	-	**-**
Materials	N/A	N/A	N/A	N/A	-	**-**
Services	N/A	N/A	N/A	N/A	0.132	**0.132**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**0.132**	**0.132**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services	0.786	0.786	0.786	0.786	0.786	**3.930**
Total	**0.786**	**0.786**	**0.786**	**0.786**	**0.786**	**3.930**

Options Analysis

Option 1 – Business as Usual (Do Nothing)

This option is not acceptable as it would mean that SA Power Networks would continue with a fleet inspections regime that does not meet our duty of care under the WHS Act and Regulations. It would have the potential for the following risks to occur:

- risk of vehicles being not fully compliant with legislation and regulations, placing an undue safety risk on employees and the community;
- potential for costly litigation or penalties imposed for non-compliance; and
- risk that any compliance issues could ground large sections of the existing SA Power Networks' fleet, impacting our ability to services to customers and meet our reliability obligations.

Option 2 – Fully outsource inspection processes

DNSPs across Australia are using various strategies to maintain legislative compliance in relation to their Elevated Work Platformss and Cranes. These range from a fully outsourced model, to a partial outsourcing model and an internally managed model. SA Power Networks has looked at these various models and deemed a fully outsourced model to be cost prohibitive.

Option 3 – Develop a partnership with a third party service provider

DNSPs across Australia are using various strategies to maintain legislative compliance in relation to their EWP's and Cranes. These range from a fully outsourced model, to a partial outsourcing model, to an internally managed model. As mentioned above, SA Power Networks has looked at these various models and deemed a fully outsourced model to be cost prohibitive.

Preferred Option
Option 3, to partner with an external service provider and become fully compliant is the preferred option as it removes the risks associated with non-compliance in the most prudent and cost-effective manner.

Alignment with NER expenditure objectives & criteria
Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Prudent and efficient vehicle inspections support our ability to meet and manage demand for SCS.
Comply with all applicable regulatory obligations or requirements	Critical information concerning the condition of vehicles is required in order to make informed decisions about safety issues (amongst other issues). The proposed increase in our inspection program is required to ensure that our fleet remains legislatively compliant with AS 2550.10 and AS 1418.10 **at a minimum** as required by the WH&S Act. The inspections also assist in ensuring compliance with other legislative obligations, such as: • SA Road Traffic Act and Regulations; • SA Motor Vehicles Act and Regulations; and • Road Transport Compliance and Enforcement.
Maintain safety of the distribution system	Prudent and efficient vehicle inspections support our ability to maintain the safety of the distribution system. The maintenance of the safety of the distribution system (including broader safety issues that are not directly related to the operation of the distribution system[10]) requires an evidenced based assessment of asset condition and associated asset failure risk to ensure that the distribution system and the equipment used to operate and maintain the distribution system, are maintained in a safe condition.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	We have identified the minimum additional resources required to achieve the relevant objective.
Cost that a prudent operator would require to achieve the objectives	We have identified that a prudent operator would require the additional resources to ensure its fleet of vehicles is operated safely and efficiently and in accordance with applicable regulatory obligations or requirements and good industry practice.

[10] As per the AEMC's comments on page 19 of the Final Rule Determination – National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013.

Operating Expenditure Criteria	Considerations
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the related objective. Cost inputs have been determined in accordance with the process outlined in Chapter 21 of the Proposal and via a competitive outsourcing process.

Supporting Documentation

- Supporting Document 21.43 – GHD: Fleet cranes and EWP Maintenance Inspection Compliance Assessment Report.
- Cost estimates for the preferred option have been generated internally and independently by Hartrite and will be made available on request.

1.3. Energy law and regulations

1.3.1 New RIN Requirements

Reference	
Proposal Section	21.6.1
SEM Category(s)	Various
Regulatory Driver(s)	Change in scope of Regulatory Obligation
Forecast: 2015-2020 (June 15 $)	$9.2m

Category Function Overview
Systems and business processes require significant change to be able to meet the AER's requirements to provide actual data for Economic Benchmarking, Category Analysis benchmarking, annual RIN and reset RIN purposes.

Description of Change
The AERs Better Regulation program has imposed new data collection and provision requirements on DNSPs.

Four mandatory RINs must be completed (three annual and one every five years), and each RIN now seeks a more granular level of financial and non-financial information (as compared to the previous RIN requirements). This level of financial and non-financial information is not currently captured by SA Power Networks systems and processes.

In addition, the information that is required to be collected and provided under the new RINs is quite complex and the resulting increase in compliance activities has had a significant cost and resourcing impact on SA Power Networks. In particular, the resourcing impact where SA Power Network employees undertook an extended effort in addition to normal work responsibilities is not sustainable and a considerable step change is therefore essential (and not unexpected).

Further, SA Power Networks' existing systems and processes, built and developed over many years, have not been configured or designed to capture and categorise information in the manner recently required by the AER's RINs. A significant portion of the information provided during 2013/14 has been estimated data. The RIN requirements going forward require the provision of actual data. The ability of existing systems to provide the required information is also compromised by the substantial number of records kept off systems, manually or in Excel Spreadsheets. This off system data is not integrated and is susceptible to error and makes provision of assurance to accuracy and completeness difficult.

In the *AER Expenditure Forecast Assessment Guideline*, the AER acknowledges that DNSPs will face expenses as a consequence of the business and operational changes required to comply with new data requirements and adjusted reporting standards. This may include (but is not limited to) training staff, adjusting IT systems, and reorganising data compliance procedures. Further the AER also recognises that it too will incur ongoing costs associated with the new assessment techniques and data requirements (including collecting and publishing data, assessing compliance with RINs and detailed reporting templates, and assessing confidentiality claims) and there will also be increased labour costs for AER staff to learn and apply new expenditure assessment techniques and the refinement of information systems. [11]

Balancing all these factors, the AER still considers the implementation of the new RIN assessment and reporting techniques and accompanying data requirements will deliver a positive net benefit. The AER believes the additional RIN imposed compliance costs to DNSPs will be outweighed by the AER's ability to maximise social benefit through the setting of efficient expenditure allowances [12].

As part of SA Power Networks consideration of its systems requirements to position SA Power Networks to meet its reliability, safety and customer service obligations we have proposed a significant investment in systems and IT infrastructure investment over the next RCP. In preparing the business cases for these systems we have (where possible) also incorporated the known RIN data requirements available at the time. Therefore to deliver the RIN outcomes required, multiple business cases (listed below) will provide the backbone to systems and processes that will enable data to be captured and collated in a way that can be subsequently applied to the RIN reporting processes.

An overarching project, RIN Reporting, is proposed to address the significant business and IT transformational change with respect to the way the business, as a whole, collects and manages information with regard to assets, projects and cost identification and categorisation. This transformation involves embedding and governing common processes, providing integration and aligned systems, the creation and availability of reliable data and a knowledgeable workforce.

Table 4: Brief description of prerequisite system developments

Business Case	Description of RIN reporting impact
Enterprise Asset Management (EAM)	This business case puts forward the key foundational components required to support RIN Reporting requirements such as: • Collection of all information about an asset at a granular level as required by AER • Costs and commissioning dates sourced from projects • Integration to CBRM, to allow costing and tracking of maintenance activities • Integration to GIS and SCADA/ADMS to support location and voltage information
Financial Management Business Case	All costs and revenues are posted to and categorised within the General Ledger. The Financial Management Business Case supports the differentiation between the allocation of costs and revenues required to meet each of Regulatory, Corporate and Statutory Reporting obligations.
Business Intelligence (BI) Business Case	Development and implementation of the necessary Business Intelligence and Performance Management capability to enhance data analysis and performance reporting functionality enabling more advanced asset performance and reliability management to provide insights that drive better decision making (including predictive decisions), asset management, customer outcomes, and regulatory reporting

[11] P 155, Better Regulation | Explanatory Statement | Expenditure Forecast Assessment Guideline
[12] P 155, Better Regulation | Explanatory Statement | Expenditure Forecast Assessment Guideline

Business Case	Description of RIN reporting impact
Integration Business Case	The integration layer is a key technology component that supports the field force in accessing and updating corporate systems as cost effectively as possible.
Field Force Mobility Business Case (Field Services)	Field Force Mobility allows time and attendance to be recorded and allocated to specific jobs. It also allows projects to be closed real time and all costs posted.
PPM Business Case	This business case covers the integrated resource and job scheduling for field workers. It also covers the integration to Time and Attendance and EAM which is a necessary capability to deliver RIN Reporting Requirements. Projects need to capture FTE hours, cost of inventory items, the nature of the work (for example, REPEX or AUGEX) and all other costs until such time as the project is closed or commissioned as an asset in the asset register.
Data Management Business Case	Underpinning the RIN Reporting requirements is a need to collect and store a wide array of detailed data. The Data Management Business Case puts forward a case for strong data management and governance capabilities.
Supply Chain Business Case	This business case puts forward the foundational integration of the supply chain to the work order management and project management to allow: • allocation of inventory/store items to specific repairs and maintenance or replacements jobs • effective costing of jobs and projects; and • accurate record of inventory as required by AER.
SAP Foundations	As SAP is the Enterprise Resource Planning (ERP) system that contains the asset and work order information, there is a dependency on the SAP roadmap to provide the back-end functionalities (e.g. maintenance orders) that is required by workers.
IT Network Foundations	The IT Network Foundations provides the technology components that enable the overall integration of GIS, OMS, SCADA and ADMS to SAP but also allows field based staff to connect to SA Power Networks corporate system irrespective of their location and device that they are using.
Enterprise Blueprint & EA Business Case	Input for Enterprise Data Architecture Model
Integrated Design Management System Business Case	Collecting more information about assets, projects and jobs requires more efficient means of delivering the available information to the field and more efficient means of collecting, organising and distributing the data once it has been updated or added by the field staff. Job packages which are based on template 'compatible units' for each asset class, which includes the standard inventory, tasks, task estimates and design information for each job and asset type provide the capability to collect the data as accurately as possible. The integration of the compatible units falls within this business case.

If funding is not received for these systems development then the stand alone RIN reporting option 3 below will be required to bridge the gap to ensure the RIN reporting requirements can be met in the most efficient and effective manner achievable. The RIN Reporting Business Case scope includes the following;

- the overall change management processes to facilitate the production of Actual (rather than Estimated) information in order to populate the RINs;

- the capability gap not delivered by the above business cases;
- defines the end to end process for ongoing capture and cataloguing of the required financial and non-financial data,
- records and reports expenditure on both network and non-network assets; and
- the development of the automatic RIN compliance reporting systems.

What stakeholders and Customer have said

The investment in systems and business capability was transparently discussed in our stakeholder engagement program and clearly outlined in our Directions and Priorities consultation. No adverse comments were received from customers in respect of these proposed investments.

Programs/ Projects required

Refer Options discussion and the systems projects outlined in the Table above.

Timing of change

Discussion will be held with the AER to discuss and agree an appropriate timeframe to achieve compliance with the various RINs where actual rather than estimated data is being requested. The commencement of the preferred option referred to in this section will be dependent on the AER's approval of the suite of system investment included in our Proposal for 2015-20.

Costing Methodology/Build Up

The costing methodology and costing outcomes for each of the options are set out in Attachment 20.39 - RIN Business Case.

No double counting (eg output/scale)

The costing of this step change is incremental to the costs incurred in the 2013/14 base year. This incremental expenditure is primarily associated with additional Non IT resources required to capture, cleanse, report and ensure compliance with the RIN requirements. These resources commence in 2017/18 following the capital investment in SAP systems. The process is detailed in the RIN business case. In addition, there are ongoing and one-off costs such as vegetation management scoping to capture the RIN data required in the first year.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	0.377	0.377	**0.754**
Materials	N/A	N/A	N/A	-	-	**-**
Services	N/A	N/A	N/A	0.877	0.877	**1.754**
Total	**N/A**	**N/A**	**N/A**	**1.254**	**1.254**	**2.508**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20) Incremental costs net of cost shown above for current RCP

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.346	0.346	2.216	2.216	2.216	**7.340**
Materials	-	-	-	-	-	**-**
Services	1.861	0.000	0.000	0.000	0.000	**1.861**
Total	**2.207**	**0.346**	**2.216**	**2.216**	**2.216**	**9.211**

Options Analysis

Option 1 - Do Nothing (implement manual process to the extent possible)
This option involves maintaining existing systems and changing work processes with increased labour resources to capture, record, collect, amalgamate, assess, verify and interpret manually recorded data. The Do Nothing option, which is unable to wholly satisfy all of the RIN requirements, results in continued reliance on manual processes and workarounds with additional RIN dedicated Asset Accountants and Data Analysts. Costs associated with this option are nil capital expenditure and $23.1 million operating costs for the next RCP. The ability to provide the level of assurance required by the AER on the accuracy and quality of the data is significantly more difficult under this option. Further the level of audit work would also be substantially higher to provide the equivalent level of signoff. This option would see this level of operating costs continue into subsequent RCPs.

Option2 - Extend SAP solution for RIN reporting
This option involves one-off capex extending our current enterprise system (SAP) which would enable an integrated approach to reviewing and redesigning business processes which will aid business long term efficiency and permit the capture of data required to comply with the AER RIN notices. This option leverages the proposed investments in SA Power Networks core systems which have been proposed as outlined above. As with option 1 this option would also involve extensive data capture and cleansing exercise of existing data sets to enable RIN compliant reporting, including a one off vegetation management scooping cost and additional internal audit fees. Audit fees under this option are expected to be lower than Option 1. Cost for this option is $15.0 million capital expenditure and $9.2 million operating costs.

Option 3 - Implement a standalone RIN reporting solution
This option involves the design, development and implementation of a stand-alone solution for RIN compliance reporting to be integrated with SAP and other SA Power Networks systems. Extensive data capture and cleansing as well as many system enhancement, interfaces and additional process enhancements will be required to maximise the level of automated and compliant RIN reporting. As with Option 2 this option would better enable full compliance with RIN notices. In the longer term the operating costs for this option are expected to be lower than the costs for Option 1. However, the costs would be higher for the next RCP. Cost for this option is $46.5 million capital and $26.6 million operating.

Preferred Option
Option 2 is considered the most prudent and cost efficient option.

Supporting Documentation
- Attachment 20.39: SA Power Networks: RIN Reporting Business Case

1.3.2 National Energy Retail Law Regulations

Reference	
Proposal Section	21.6.1
SEM Category(s)	A-33 Customer Relations (excl Call Centre)
Regulatory Driver(s)	Change in Legal and Regulatory Obligations
Forecast: 2015-2020 (June 15 $)	$4.3m

Category Function Overview
The current derogation exempts SA Power Networks from the requirement to provide four days written notice of planned outages less than 15 minutes duration (as detailed in the South Australian National Energy Retail Law (Local Provisions) Regulations 2013 section 14(6)). This derogation expires on 30 June 2015. The expiration of the derogation will require SA Power Network to incur additional costs related to such notifications and other associated costs from1 July 2015.

Description of the Change
Clause 90 of the National Energy Retail Rules (**RR**) requires that a distributor provide customers with four business days prior notice of a planned interruption regardless of its duration. Currently, SA Power Networks is required to provide customers with four business days prior notice for planned interruptions only where the duration exceeds 15 minutes. With the lapsing of the derogation, as from 1 July 2015, SA Power Networks must provide customers with four business days notice where the duration of the planned interruption is less than 15 minutes.

The current derogation from clause 90 of the RR continued the jurisdictional arrangement that existed prior to the implementation of the National Energy Customer Framework (NECF). The derogation was granted to minimise any increase in costs associated with the implementation of the NECF.

A request has been lodged with the South Australian Government for an open ended extension of the current derogation, (i.e. to excuse SA Power Networks from the obligation to provide four prior business days notice of a planned interruption where the duration of the planned interruption is less than 15 minutes). If an extension of the current derogation is not provided then the forecast cost of this additional notification and the associated increased administration costs amounts to $4.3 million over the five years for SCS and $6.2 million for ACS.

Timing of the change
1 July 2015.

Costing Methodology/Build Up

The additional cost is a mix of:

- interruptions where no prior notice has been provided under the current derogation because the duration of the interruption is less than 15 minutes; and
- planned high voltage (HV) switching, where the majority of customers affected by the planned interruption, have not been provided with four business days notice under the current derogation, as the relevant customers experience two interruptions less than 15 minutes as a result of the switching to safely isolate the line section on which work is to be performed.

The costing is based on the 2012/13 regulatory year, in which there were 298 interruptions impacting a total of 101,045 customers. The incremental SCS average cost equates to a total of $4.3 million over the 5 years of the next RCP.

The forecast cost has been determined on the basis of the extra time (@ $100 per hour) to prepare the notice, determine the customers affected and post the letter to customers (@ $0.72 per letter). Extra customer telephone queries at $12 a telephone call (ie 6 minutes per call).

No Double Counting of operating costs

This is a new regulatory requirement resulting from the expiration of the derogation and therefore no costs have been incurred in the current RCP (and, in particular, in our base year) in relation to this activity. Consequently, there is no duplication of costs associated with this in regard to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	N/A
Materials	N/A	N/A	N/A	N/A	N/A	N/A
Services	N/A	N/A	N/A	N/A	N/A	N/A
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.241	0.241	0.241	0.241	0.241	**1.205**
Materials	-	-	-	-	-	**-**
Services	0.620	0.620	0.620	0.620	0.620	**3.100**
Total	**0.861**	**0.861**	**0.861**	**0.861**	**0.861**	**4.305**

Options Analysis

Option 1 – Continue with current arrangements
This option can only be viable if the SA government agrees to an extension of the current derogation. The Government has publicly consulted on whether to extend or not. At the time of preparing this Attachment a decision of the Government in this regard has not been announced. In the event a favourable decision is made to extend then derogation the costs outlined in Option 2 and included in these step changes would be removed.

Option 2 – Undertake the necessary notifications for planned work of any duration
As discussed there are two components that incur costs in meeting this changed regulatory obligation. Firstly, the administrative costs of preparing and sending notices. Secondly, the operational inefficiencies associated with being unable to carry out certain tasks efficiently. A third aspect is the impact of these arrangements on interruptions to customers supply.

An important aspect in understanding the increased costs is an explanation of planned High Voltage (HV) switching arrangements.

The distribution network is designed with switches which enable a section of the network to be de-energised so that planned work can be performed safely. These switches fall into two basic categories, which are 'live[13]" and "dead[14]" operation. As the cost of a live switch is many times the cost of a dead switch the majority of switching points are of a dead switch type (ie only operate in a de-energised state).

SA Power Networks typically operates both live and dead operation switches in sequences designed to minimise the number of customers affected by a planned outage. However, in some instances this means that customers are subject to two short duration outages (ie less than 15 minutes), one prior to and one after the work is complete, with a subset of those customers seeing a single long duration interruption. The sequence of switching in these instances is:

- live switch opened and all customers downstream of the switch are without power;
- downstream dead operation switch opened to isolate section of network affected by planned work; and
- live switch closed to restore supply to all downstream customers, except those supplied from the network section where the work is being performed.

Once the work is completed the opposite switching steps are performed to restore supply to all customers impacted by the planned work.

This results in the majority of customers receiving no prior notice of the two planned short duration outages and the customers supplied by the network section affected by the planned work experiencing an outage of a longer duration. These latter customers currently receive four business days prior notice.

As from 1 July 2015 SA Power Networks will be required to notify those customers where supply will be interrupted twice by two interruptions with the duration of each interruption being less than 15 minutes. Notifications are not currently provided to those customers so the costs are not included in the 2013/2014 base year.

[13] A "live" switch can be operated (ie opened or closed) whilst the sections of the network which it connects are either dead (de-energised) or live (energised) switch is energised or live.
[14] A "dead" switch can only be operated when the sections of the network it connects are dead (de-energised).

Preferred Option

SA Power Networks preferred option is Option 1. However, this is only feasible if the SA Government approves an extension of the current derogation. Accordingly, unless the current derogation is extended SA Power Networks will be obligated to incur the step change costs of Option 2. These costs have been included in our Proposal.

Alignment with NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Recovery of SAPN's efficient costs of complying with this regulatory obligation will support our ability to meet and manage demand for SCS.
Comply with all applicable regulatory obligations or requirements	If the SA Government does not grant a continuation of the current derogation relating to notifying customers of planned interruptions with a duration of less than 15 minutes, SAPN must comply with RR 90. Additional expenditure will be required to meet these increased notification requirements.
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	Recovery of SAPN's efficient costs of complying with this regulatory obligation will support our ability to maintain reliability and security of supply.
Maintain safety of the distribution system	Recovery of SAPN's efficient costs of complying with this regulatory obligation will support our ability to maintain safety of the distribution system.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach results in the lowest cost to consumers in the long term to comply with this obligation. We will be able to avoid this cost altogether if the current derogation is extended.
Cost that a prudent operator would require to achieve the objectives	Our approach reflects the cost a prudent operator would incur given that SA Power Networks must comply with this requirement.
Realistic expectation of demand and cost inputs required to achieve the objectives	Our supporting documentation demonstrates that our proposed expenditure meets this criterion.

1.3.3 National Energy Customer Framework

Reference	
Proposal Section	21.6.1
SEM Category(s)	DA-3 Customer Service
Regulatory Driver(s)	Change in Legal and Regulatory Obligations - Full adoption of the National Energy Customer Framework (NECF) from 1 July 2015
Forecast: 2015-2020 (June 15 $)	$1.3m

Category Function Overview
To meet the requirements of our new connection policy and charging regime based on the National Energy Customer Framework (**NECF**) requirements which come into effect in South Australia on 1 July 2015.

Description of the Change
SA Government 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.

The NECF imposes a number of obligations on SA Power Networks over the next RCP (1 July 2015 to 30 June 2020), requiring staff to undertake a number of additional or expanded activities. These activities include, but are not limited to:

- Pioneer Scheme, administration.
- Distribution Use of System (DUoS), management and analysis of SA Power Networks rebate schemes.
- Augmentation calculations, management and analysis of the information for customer connections.
- Additional regulatory reporting, service standards and category data analysis.

SA Power Networks has prepared a Connection Policy to cover connection services provided over the 2015-2020 RCP. The Connection Policy sets out the circumstances in which SA Power Networks may require a retail customer or real estate developer to pay a connection charge, for the provision of a connection service under Chapter 5A of the National Electricity Rules.

The NECF administrative obligations are required to comply with AER approved Connection Policy. This will require staff to undertake a number of additional or expanded activities to manage the customer information, schemes and the risks arising from the complexity of the new or revised obligations. These include, but are not limited to:

- Pioneer Scheme: This cost share scheme will greatly expand SA Power Networks' operations to ensure compliance, resulting in the expansion of the scope of our rebate schemes. Consequently, this will require additional operating expenditures for the management and analysis of customer connections related information, which has not been required in the current RCP.
- Distribution Use of System (DUoS) rebates: This new obligation will result in a more complex and longer period of rebate for customer connections. These changes to the rebate schemes for the 2015-2020 RCP will require SA Power Networks to change our practices, resulting in additional operating expenditures for the management and analysis of our rebate schemes.
- Augmentation calculations: Similar to the extended period and complexity of the DUoS rebate, our augmentation charging principles will need to be aligned with the new principles to ensure compliance. This will result in additional operating expenditures to manage and analyse the information for customer connections.
- Reporting: Service standards reporting for all connection services at all customer levels, plus additional and new data collection, monitoring and analysis for regulatory reporting (e.g. Category Analysis).

What stakeholders and Customer have said
There are no specific customer engagement outcomes relevant to this changed regulatory obligation.

Programs/ Projects required
All the new NECF customer connection services administrative obligations will be embedded within established or new SA Power Network AS/NZS ISO 9001:2008 accredited Quality Management System processes and business reporting frameworks.

Due to the changes in practices, there will potentially be further IT capital investments for system changes and/or new systems to support the operational changes. These forecast capex investments will be required to be completed in 2015.

Timing of change
Preparation work will be undertaken during 2014/15 to ensure we can administer the additional NECF obligations from1 July 2015.

Costing Methodology/Build Up
SA Power Networks has forecast for a step change in operational investment for customer connections services of $1.29 million over the 2015-2020 RCP to manage and be compliant to the NEFC obligations. This forecast is estimated on the basis of two additional full time employees (**FTEs**) to centrally manage these additional activities and to ensure consistency and compliance with these obligations. The basis of estimation is detailed in Table 5 below.

These costs are the incremental cost of complying with these new regulatory obligations. These are new obligations and therefore the costs have not been incurred in relation to these new obligations during the current RCP and, in particular, in our base year. Consequently, there is no duplication of costs associated with this in regard to output growth.

Table 5: Forecast incremental hours effort required to fully comply with NECF obligations from 1 July 2015

Item	Time (hours)	Existing projects (No.)	New Projects (No.)	Incremental Change (No.)	Time required (hours)
Pioneer Scheme Governance					
• Developing and maintaining the Pioneer Scheme database	.1	300	1500	1200	120
• Pioneer Scheme expiration	.1	300	1500	1200	120
• Customer Refunds expiration	.1	300	1500	1200	120
• Provide advice in relation to existence and operation of a Pioneer Scheme	.1	300	1500	1200	120
Pioneer Scheme Calculations					
• Determine the Current and new loads	.1	300	1500	1200	120
• Determine the length of line used	.1	0	1500	1500	150
• Determine depreciation	.1	0	1500	1500	150
• Determine the number of equivalent customers	.1	0	1500	500	150
• Calculate contributions and rebates	.3	300	1500	1200	360
Equalisation Scheme Governance					
• Developing and Maintaining the Equalisation Scheme database	.3	0	200	200	60
Equalisation Scheme Calculations					
• Calculate costs associated with an equalisation scheme	4.0	0	200	200	800
Augmentation					
• Costs calculation	.3	700	1100	400	120
Incremental Revenue Governance					
• Developing and maintaining the IRR database	.2	0	2300	2300	460
• Develop standard IRRs for customer types	100.0	0	1	1	100
Incremental Revenue Calculation	1	700	2300	1600	1600
RIN framework Governance Developing and Maintaining the RIN framework database	.1	0	2300	2300	230
Total effort in hours					4780

The Opex estimate was based on 2 FTEs, a Connection Charge Co-ordinator and a Connection Analyst, each at an equivalent pay of grade 7. It is proposed that one of these positions, the Connection Charge Co-ordinator, will commence in January 2015 to help establish the required administrative systems for SA Power Networks to comply from 1 July 2015.

No double counting (eg output/scale)
The additional effort outlined the above table is equivalent to 3FTE's. However, we have assessed a portion of this additional work will be completed by existing field employees hence the incremental cost of 2 FTEs has been included in the step change.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	0.065	**0.065**
Materials	N/A	N/A	N/A	N/A	-	**-**
Services	N/A	N/A	N/A	N/A	**-**	**-**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**0.065**	**0.065**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.258	0.258	0.258	0.258	0.258	**1.290**
Materials	-	-	-	-	-	**-**
Services	-	-	-	-	-	**-**
Total	**0.258**	**0.258**	**0.258**	**0.258**	**0.258**	**1.290**

Options Analysis

Option 1 – Business as Usual (Do Nothing)
This option is not feasible as we are required to meet the additional regulatory obligations under NECF as well as the regulated service standards.

Option 2 – Implement all administrative obligations and adequately resource from a central business location to meet compliance.
The NECF charging regime introduces substantially more variability into the charging for individual connections and it is forecast that a step increase in the complexity and associated communications with customers will occur. Accordingly, it is prudent that the proposed administrative arrangements are established by 1 July 2015 to ensure compliance with and the consistent application of the additional obligations relating to connections.

As detailed in the table above there is approximately 2300 individual connection projects for retail and real estate customers each year that will require some form of compliance processing and ongoing monitoring under the new NECF obligations. An assessment has been made on the 14 main process items, the effort in hours to administer for each, the likely volume of projects for an average connection services work year to determine a total incremental hours effort required to fully comply with NECF obligations.

Alignment with NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Prudent and efficient resourcing to comply with these new regulatory obligations will support our ability to meet and manage demand for SCS.
Comply with all applicable regulatory obligations or requirements	A new framework has been established across the NEM known as the National Energy Customer Framework (NECF). Prior to the NECF, each state, including South Australia, had its own jurisdictional arrangements. The SA Government partially adopted the NECF on 1 February 2013, with the intention of full adoption from 1 July 2015 (including the NECF connection charging obligations). The NECF applies to all SA Power Networks Customers who apply for a connection service. The NECF imposes a number of obligations on SA Power Networks over the 2015-2020 RCP, which require staff to undertake additional or expanded activities. These activities include, but are not limited to: • Pioneer Scheme, administration. • Distribution Use of System (DUoS), management and analysis of our rebate schemes. • Augmentation calculations, management and analysis the information for customer connections. • Regulatory Reporting, Service standards and a broad range of Category Analysis. •
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	Prudent and efficient resourcing to comply with these new regulatory obligations will support our ability to maintain quality, reliability and security of supply.
Maintain safety of the distribution system	Prudent and efficient resourcing to comply with these new regulatory obligations will support our ability to maintain the safety of the distribution system.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach results in the lowest cost to consumers in the long term to comply with this obligation.
Cost that a prudent operator would require to achieve the objectives	Our approach reflects the cost a prudent operator would incur given that SA Power Networks must comply with this requirement.
Realistic expectation of demand and cost inputs required to achieve the objectives	Our supporting documentation demonstrates that our proposed expenditure meets this criterion.

Supporting Documentation

- Supporting Document 21.44 – SA Power Networks: Connection Management Plan (AMP 7.1.01)

1.3.4 Demand Side Participation

Reference	
Proposal Section	21.6.1
SEM Category(s)	Multiple
Regulatory Driver(s)	Change in Legal and Regulatory Obligations
Forecast: 2015-2020 (June 15 $)	$33.8m

Category Function Overview
Initiatives to adapt and respond to forecast step change increases in Demand Side Participation (DSP).

Description of the Change
Increasing DSP and emerging technologies such as battery storage and electric vehicles are changing the role of the network from a one-way energy distribution system to an active two-way grid that connects a dynamic web of distributed consumption and generation resources. This creates new challenges in how we manage and operate the network, particularly the low voltage (LV) network. It also means that the way we charge most customers for their use of the network, which is currently in proportion to the amount of energy they import from the grid, is no longer appropriate as it accentuates the level of cross-subsidies between customers. For example, customers with their own generation may place considerable demands on the network at peak times but have low or even negative net import over the course of a year.

We propose to respond to these challenges in the 2015-2020 RCP by:

- commencing a transition to more cost-reflective network tariffs for small market customers;
- installing advanced meters as standard to support these tariffs that are also upgradable, or 'smart ready'; and
- making use of the opportunities created by smarter metering as a cost-efficient platform for monitoring power quality in the LV network and for broader network benefits.

Program/projects required

Transition to cost-reflective network tariffs
From July 2015 we propose to transition small-market customers to a new cost-reflective network tariff based on maximum demand, as follows:

- From July 2015 to July 2017 the tariff will be made available on a limited, predominantly opt-in basis.
- From July 2017 the tariff will be mandatory for all new customers and all customers upgrading their supply arrangements (e.g. to install 3-phase power, solar photovoltaic (PV), etc). Other customers will be able to access the tariff on an opt-in basis.

Our proposed approach transitions customers to a cost-reflective tariff at the time at which they are making new demand-side investment decisions. This will preserve existing customer investments while allowing customer decisions on emerging technologies to be based on efficient pricing. It will also minimise the cost of the new metering required to enable new tariffs, since these customers would require a new meter in any event. We expect to transition around [redacted] per annum to the new tariff from July 2017 under this approach, phasing in the tariff progressively over the next two RCPs.

As the new tariff is calculated monthly, we also propose to transition all customers from a quarterly to a monthly meter reading cycle from mid 2017.

In order to achieve the necessary transition to cost-reflective tariffs with minimal customer impact, we propose a comprehensive customer and retailer education and engagement programme, including additional call centre resources to support customers in understanding the tariff and maximising their benefit.

Smarter meters as a tool to manage the two-way grid

We propose both to facilitate a transition to smarter metering in South Australia from 2015 onwards, and to position to unlock the network benefits that smarter meters can offer, by:

- moving to an upgradable 'smart ready' interval meter as our standard meter for regulated metering services, as a more capable meter is required to enable new capacity tariffs;
- establishing IT systems, business processes and market gateway interfaces required to enable network benefits from smart meters, including smart meters deployed by third parties under a market-led rollout (via the proposed AEMO market gateway); and
- enabling telecommunications on a targeted subset of our own 'smart ready' meters to establish a core capability in network monitoring across specific areas of the LV network.

The primary goal is to establish a capability to actively monitor power quality at the customer premises, where we have almost no monitoring today. As solar PV penetration grows, the grid becomes increasingly characterised by two-way energy flows at the LV network level, and current approaches to voltage regulation are no longer expected to be sufficient to maintain voltage at the customer supply point to regulated standards.

What our stakeholders and customers have said to us

Our CEP confirmed that:

- 68% of customers surveyed supported the phased introduction of tariffs that more closely reflect usage of the network;
- 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 are consuming less energy in response to rising electricity retail prices and they are investing in local solar PV generation, accelerated by generous government incentives;
- customers are changing the way they use the network with their continued uptake of DER (such as 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 DER 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 distributed energy resources.

Costing Methodology/Build Up

Our proposed tariff and metering program has the following SCS opex components in the 2015-20 period:

- support and maintenance of new IT systems to enable the proposed tariff to be implemented, and to process the increased volumes of data from smarter meters, both those we install and those that third parties install that we access through the market gateway;

- customer and retailer engagement to support customers through the transition to our new network tariff; and
- telecommunications opex for a subset of the meters we install, to enable power quality monitoring and other operational benefits.

Opex cost estimates have been prepared on the following basis:

- Take-up rates for new tariff have been estimated as follows:
- New customer connection forecasts are those used for network planning, and are based on demographic data and forecasts prepared by BIS Shrapnel.
- Solar uptake forecasts are based on modelling undertaken by Energeia.
- Service alterations are only those that involve a meter replacement, e.g. upgrade of supply to three-phase. Forecasts are based on historical data.
- Annual voluntary opt-in rates are forecast at 2% per annum following the launch of the tariff, based on results from customer surveys undertaken by UMR.
- Estimates have been prepared by Deloitte for opex components of IT systems upgrades to support capacity tariffs (inc IEE, MTS), as well as ongoing application and user support and maintenance for billing related systems, data analytics, ADMS and OMS integration, external market gateway interfaces, IT security assessment and security management services (not included in the IT step change discussed in section 2.1).
- Impact on billing component of managed services contract for FRC systems support due to transition to all-monthly billing has been estimated in consultation with service providers.
- Vendor support and maintenance of IT hardware and software estimated by Deloitte at 20% of associated capex (these costs have not been included in the IT step change discussed in section 2.1).
- Opex estimates for customer and retailer engagement activities are based on modelling estimated customer call centre contact rates arising from the introduction of the new tariff, as well as ongoing retailer support, drawing on experience of call-centre impact due to introduction of solar feed-in tariffs.
- Opex includes new requirement for 2 x FTE from year 2 to manage ongoing commercial and logistical arrangements with multiple meter providers, including meter asset transfer, arising from transition to full contestability in metering services.
- Additional staff resources associated with LV monitoring using telecommunications-enabled meters includes meter test & certification group resource uplift to support firmware configuration management, commissioning, field support for deployment, non-standard installations, troubleshooting and telecommunications issues during deployment phase, and ongoing maintenance for active devices in the field. All estimates were prepared with assistance of Deloitte drawing on experience from Victorian AMI program.
- 3G data costs estimated based on current contracts and EOI process.

Full details are provided in the Tariff and Metering Business Case.

No double counting of opex
This program relates to the introduction of smart ready meters and cost-reflective tariffs in the next RCP. The step change costs associated with these initiatives are in addition to our base year costs.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	N/A
Materials	N/A	N/A	N/A	N/A	N/A	N/A
Services	N/A	N/A	N/A	N/A	N/A	N/A
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.818	2.158	4.403	4.963	5.651	**17.993**
Materials	0.000	0.048	0.056	0.101	0.104	**0.309**
Services	0.382	1.647	4.012	4.621	4.883	**15.545**
Total	**1.200**	**3.853**	**8.471**	**9.685**	**10.638**	**33.847**

Options Analysis

Option 1 – Business as Usual (Do Nothing)

This option would be inconsistent with the energy market reforms currently being progressed by the AEMC through their power of choice review and the associated rule changes. Further it would be inconsistent with the strong customer support for tariff reform arising through our Customer Engagement Program and the draft new and replacement policy of the SA Government currently being consulted on.

Option 2 – progressive implementation of Advanced meters and cost-reflective tariffs

Detailed economic modelling by consultant Energeia commissioned by SA Power Networks indicates that the transition to a cost-reflective network tariff will deliver a number of benefits:

- It will arrest cross-subsidies that are driving increasing network costs for those customers that do not have their own distributed energy resources (DER). In 2014, we estimate that the total subsidy of PV customers by non-PV customers in South Australia will be around $16 million, and this is growing year-on-year as PV penetration continues to rise.
- It will give customers the opportunity to save money by using the network efficiently, placing downward pressure on future peak demand growth by encouraging customers to shift discretionary load outside of peak hours.
- It will drive more efficient demand-side investment choices, increasing utilisation of existing network assets and reducing total cost of energy to the community in the long term.

Energeia's model compared four different future network tariff scenarios and concluded that network tariffs with component based on maximum demand delivered better long-term outcomes than inclining block tariffs (IBT) or tariffs based on Time of Use (ToU).

Our proposed approach results from key recommendations of the AEMC *Power of Choice* review and the Productivity Commission. It aligns fully with the AEMC's recent draft determination on the current proposed rule change relating to future distribution network pricing, which proposes:

- Network service providers should phase in cost-reflective tariffs, with 2017 proposed as a timeframe for introduction; and
- Networks service providers will be required to minimise the impacts of price changes on consumers, for example by gradually transitioning to new prices over 5 years or more.

The AEMC estimates that up to 81% of consumers would face lower network charges in the medium term under a cost-reflective capacity price, and finds that capacity pricing is more beneficial than alternatives such as critical peak pricing. This aligns with the findings of our own research.
As well as enabling tariff reform, we propose to make use of the opportunity created by more advanced metering to establish a capability to actively monitor power quality at the extremities of the LV network at much lower cost than grid-side alternatives.

A study by consultants PSC found that across older areas of the LV network, existing network infrastructure and voltage regulation approaches limit acceptable solar PV penetration to around 25% of customers. Solar PV penetration is already reaching this level in some areas, and is forecast to continue to grow in South Australia, rising to 40% of premises by 2020 and more than 50% by 2025. If we are to continue to accommodate solar PV and other distributed energy resources connected at the LV network while maintaining power quality at the customer supply point to Australian standards, we urgently require the capability to actively monitor voltage in the LV network.

Our proposed approach is to enable three 3-phase meters for voltage monitoring per LV circuit in target areas. This will achieve the capability we require for a total cost (CAPEX and OPEX, 15 year NPV) that is 50%-60% of the cost of an alternative grid-side solution.

As well as power quality monitoring, we propose to enable a range of other network benefits from smart meters, drawing on experience in Victoria, including outage notification, remote testing, load control and others. These benefits will accrue predominantly in the medium- to long-term (i.e in the 2015-20 RCP and beyond) when the penetration of smart meters in South Australia grows under a market-led meter rollout realises sufficient levels to enable these benefits to be obtained.

Based on the most recent studies by Deloitte and Energeia, the future value of these benefits in South Australia (15 year NPV) is estimated at between $21 million and $180 million, depending on the rate of uptake of smart meters in a market-led rollout. In addition, we estimate a further $3-4 million in future benefits from the small subset of meters enabled with communications under our targeted power quality monitoring programme.

Preferred Option
Option 2 is the preferred option and has been incorporated into our Proposal.

Alignment with the NER expenditure objectives & criteria
Our proposed approach aligns with customer priorities and government policy objectives:

- It aligns fully with the AEMC's draft determination on the current proposed rule change relating to future distribution network pricing.

- It addresses customers' priorities expressed through our 2013 *TalkingPower*[TM] stakeholder consultation program, in particular customer insights #10 – #13:

  #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.

- It addresses the needs of the South Australian business community. In a survey of members prior to the last State election, Business SA found that *"80% of respondents supported a rollout of smart meters"* while noting that *"it will be critical that the transition to smart meters is managed to minimise any additional cost on business, particularly small business."*.
- It also aligns with the SA Government's proposed 'new and replacement' policy for advanced metering, and the objectives of a market-led smart meter rollout.

Finally, the overarching principles that have guided our proposed approach are the operating expenditure objectives, in particular:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Effective tariff reform is central to managing the expected demand for SCS over the 2015-2020 RCP and beyond. By phasing in cost-reflective network tariffs for customers at the point at which they are making investment decisions that will affect their demand on the network, we will encourage choices and behaviors that will increase utilization of existing network assets, reducing the need for network augmentation in the long term.
Comply with all applicable regulatory obligations or requirements	We have a regulated requirement to maintain power quality at the customer supply point to Australian standards. Increasing penetration of solar PV is causing unprecedented variations in voltage across older areas of the low voltage network. If we are to continue to meet our regulatory obligations in relation to power quality over the 2015-2020 RCP and beyond we require active monitoring at the LV network level in these areas. We propose to achieve this in an efficient way by enabling power quality monitoring on a targeted subset of 3-phase meters.
Maintain safety of the distribution system	While this objective is not the primary driver for this approach, experience from the Victorian roll out has demonstrated that a transition to smarter metering can deliver a number of safety benefits, for example, the detection of degraded neutral at the customer premises, detection of continued energy export from embedded generators during loss of grid supply due to inverter faults, and so on.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Through our proposed 'new and upgrade' approach to phasing in new tariffs and new meters we are seeking to achieve our objectives in tariff reform and LV network monitoring as cost-efficiently as possible. From a system-wide perspective, aligning network pricing to cost will drive more efficient use of network assets, minimising network cost in the long term.
Cost that a prudent operator would require to achieve the objectives	We consider that this approach is required for us to appropriately discharge these responsibilities and meet the needs of customers in the 2015-2020 RCP and beyond. In particular, it would be *imprudent* to: • fail to respond to rising network prices and decreasing network utilisation caused by inappropriate price signals in our current tariffs; • fail to act to mitigate the predicted emergence of widespread power quality issues as solar PV penetration exceeds the limits of current infrastructure on feeders across all older areas of the LV network; and • continue to install obsolete and non-upgradable accumulation meters that cannot support new tariffs or provide the data customers need to understand and manage their energy use.
Realistic expectation of demand and cost inputs required to achieve the objectives	We have engaged appropriately qualified and experienced industry consultants including Energeia, Deloitte, PSC, Ernst and Young, BIS Shrapnel, UMR and others in order to develop the demand and cost inputs for this approach.

Supporting Documentation

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 - SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Attachment 14.3 – SA Power Networks: Tariff and Metering Business case

1.3.5 Environmental Management

Reference	
Proposal Section	21.6.1
SEM Category(s)	A-27 Environmental
Regulatory Driver(s)	Change in Legal and Regulatory Obligations
Forecast: 2015-2020 (June 15 $)	$1.4m

Category Function Overview
Initiatives to ensure SA Power Networks has sufficient resources available to meet increasing onerous environmental laws and growing general community expectations in regard to prudent management of the environment.

Description of the Change
As a business SA Power Networks is committed to conducting our electricity distribution operations and business activities in a manner that prevents or minimises pollution and other adverse impacts on the environment. To facilitate this, the Environment Branch implements a number of programs and undertakes a variety of functions, including:

- Monitoring the organisation's environmental awareness and performance;
- Environmental reporting, including:
- External – NGERS (greenhouse gas emissions), NPI (pollution emissions); and
- Internal – staff communications, Environmental Management Committee, Executive Management Group, corporate and Annual Reports;
- Managing environmental incidents and assisting with customer enquiries and complaints;
- Providing environmental advice (e.g. vegetation clearance, noise, biodiversity, bio-security, waste, soil contamination, EMF, Aboriginal/cultural heritage, oil filled asset management) to Project Managers and other stakeholders;
- Developing and reviewing project documentation (e.g. approvals, Site/Construction Environmental Management Plans);
- Managing the assessment and remediation of site contamination resulting from current and past activities;
- Liaising with the SA Environment Protection Authority (**EPA**) and other regulatory and industry bodies to maintain and improve compliance;
- Developing, implementing and promoting sustainability initiatives (e.g. recycling, resource efficiency);
- Conducting environmental audits at work sites, depots and substations; and
- Developing and delivering Environmental Awareness and other specialised training.

Prior to and throughout the current RCP we have seen numerous changes to environmental related laws. These are discussed in detail below. SA Power Networks forecasts that this trend in new and more stringent environmental regulatory mechanisms, as well as increased community expectations, will require additional resources in the Environment Branch in the next RCP to enable prudent management of these activities.

Environmental management is an important function that SA Power Networks undertakes as part of ongoing business operations to ensure that we minimise the potential for adverse impacts on the environment and the community. The environmental regulatory landscape has changed significantly in recent years, with the introduction of new and more stringent legislation, regulations, policies, guidelines and standards. We have been able to manage the impact of these changes with current resourcing levels but have no capacity to address further developments that will arise from the most recent changes and are expected to arise during the next RCP.

The introduction of new regulatory mechanisms typically involves a period of industry and community consultation by the relevant regulator. There is subsequently a transitional (grace) period during which stakeholders can allocate resources to develop the systems and processes required to achieve compliance. Several of the regulatory mechanisms described in the following sections have only recently been introduced or have not yet been finalised. As such, there is a lag between regulatory changes occurring and the implementation of our response and the allocation of resources to undertake the required work associated with their roll-out.

SA Power Networks takes its regulatory obligations and community expectations seriously, and strives for ongoing improvement in the area of environmental compliance.

Site Contamination

Two key regulatory mechanisms in the site contamination assessment and remediation space have undergone extensive revision in the last couple of years. In 2013 amendments to the *National Environment Protection (Assessment of Site Contamination) Measure 1999* (**NEPM**) came into force. The key impacts of the NEPM amendments are the changes made to the technical guidelines which contain standards and practices for the investigation and assessment of various contaminants. In particular, changes have been made in relation to:

- The approach to site characterisation;
- Investigation levels for evaluating potential human health risks associated with soil and groundwater impacts;
- Ecological investigation levels; and
- The frameworks for assessment of potential human health and ecological risks.

In response to the introduction of the NEPM amendments, the SA EPA released the draft *Guidelines for the assessment and remediation of site contamination* for consultation. The EPA expects the final version of the Guidelines to be published in 2015. In addition to incorporating the changes introduced by the NEPM, the Guidelines build on the site contamination provisions added to the *Environment Protection Act 1993* (SA) in 2007 and associated *Environment Protection Regulations 2008*.

The result of these more stringent regulatory mechanisms is that for SA Power Networks sites at which contamination has been identified or there is the potential for material environmental harm or impact to groundwater, increased levels of investigation and remediation are required.

The same requirements apply to the investigation of actual or potential environmental harm as a result of an environmental incident such as a significant oil spill from a transformer rupture. As such, the immediate and ongoing costs and resources required for managing land and groundwater contaminated as a result of business activities and operations will increase.

Waste Management and Soil Management

In 2010 the SA EPA introduced two key regulatory mechanisms that have resulted in significant changes in the way that SA Power Networks manages waste and waste soil. Both the *Standard for the production and use of Waste Derived Fill 2010* and the *Environment Protection (Waste to Resources Policy) 2010* aim to increase the recovery of resources for beneficial reuse through additional and more stringent categories of recyclables and increased gate fees for waste being disposed to landfill.

<u>Waste Soil Management</u> - SA Power Networks undertakes a large range of activities (e.g. underground cabling, and the replacement, upgrade or installation of infrastructure) that can generate soil that needs to be removed from the location from which it was excavated.

The new *Standard for the production and use of Waste Derived Fill 2010* has resulted in the development and implementation of new internal guidelines for managing waste soil, including additional requirements for sampling, testing, interpretation of results, transport and disposal. As a consequence, the costs and resources (both internal and external consultancies) for waste soil management have increased substantially.

<u>Waste and Recycling Management</u> - As a large and geographically dispersed organisation, SA Power Networks has unique challenges with respect to the sorting, collection and disposal of waste and recyclables.

In line with the *Standard* described above, the new *Waste to Resources Policy 2010* introduced additional and more stringent requirements for the classification, sorting, collection and disposal of general waste and recyclables. In response, SA Power Networks has introduced a new system and service provider for waste and recycling management. The management and monitoring of these systems and providers has resulted in increased human resources and services expenditure.

Water Quality and Bunding of Oil Filled Assets

<u>Water Quality</u> - The *Environment Protection Act 1993* and the *Environment Protection (Water Quality) Policy 2003* places a legal responsibility on SA Power Networks not to undertake any activity that pollutes, or has the potential to pollute, the environment unless SA Power Networks takes all reasonable and practicable measures to prevent or minimise any resulting harm.
The *Water Quality Policy* is currently under review by the EPA, with the new/amended *Policy* expected to be released in the next few months. It is anticipated that additional testing and management requirements will form part of the revised Policy.

<u>Bunding of Oil Filled Assets</u> - Substantial fines or imprisonment may be imposed for pollution that results in environmental harm with additional penalties possible where a company deliberately delays or avoids costs associated with oil containment.

SA Power Networks is required by the SA EPA to bund transformers containing oil that may pose a risk of pollution to the surrounding environment. The SA EPA "*Bunding and spill management Guideline*" was updated in 2012 and includes more stringent requirements for bunds and spill containment systems.

As part of SA Power Networks' management program for oil filled assets, substations and high risk ground level and pad mount transformers are regularly audited against a range of environmental criteria. With the additional requirements arising from the revised *Water Quality Policy* and *Bunding Guidelines*, more regular and involved auditing is anticipated.

Native Vegetation
Under the *Native Vegetation Act 1991*, legal clearance of native vegetation may be permissible through one of two mechanisms: either by an application to the Native Vegetation Council OR under exemptions contained within the Native Vegetation Regulations.

The Regulations assist in the day-to-day management of an area or property by setting out circumstances in which native vegetation may be cleared without the need for specific consent from the Native Vegetation Council. In some cases, while clearance may be exempt by the Native Vegetation Regulations, there may be constraints under other legislation that need to be complied with, such as the *River Murray Act 2003, Water Resources Act 1997, Natural Resources Management Act 2004, Development Act 1993, Adelaide Dolphin Sanctuary Act 2005* and the Commonwealth *Environment Protection and Biodiversity Conservation Act 1999*.

There have been amendments made to the Regulations in 2009 and again in 2012 which require additional resources to facilitate the interpretation and implementation of the Regulations and the exemptions contained within on a project by project basis. This includes provision for further staff training and the costs incurred through utilising approved consultancies undertaking inspection and reporting functions to the Native Vegetation Council.

Electric and Magnetic Fields (EMF)
The Australian Radiation and Protection and Nuclear Safety Agency (ARPANSA) has been developing guidelines for EMF in the low frequency range (0 to 3 kHz) from around 2002, to replace the current 50 Hz NHMRC EMF Guidelines of 1989. A working group produced the first draft in 2007 but due to a number of controversial issues (such as the precautionary principle), problems with the Regulatory Impact Statement and staff changes at ARPANSA, the EMF Guidelines has not been finalised. ARPANSA has produced a revised version (draft of December 2012) and has scheduled a final release of the guideline for the last quarter in 2014 for the technical measurement components and a precautionary principle component in the first quarter of 2015. This release is hoped to coincide with a World Health organisation (WHO) document on approaches to the precautionary principle for managing public EMF exposure.

The current electricity industry approach of prudent avoidance is to do what is reasonable to reduce magnetic fields and a typical figure of expenditure for a new project is up to 4% of total project cost. ARPANSA has outlined an approach to determine the appropriate level of expenditure to meet the precautionary approach as a hard dollar figure per child in the area affected by distribution lines and substations. This money would then be required to be spent on reducing EMF exposure for the nominated asset.

Based on the draft of the EMF guideline an increase in cost increase in the resources and equipment has been estimated for the testing and monitoring of substation and distribution lines assets to ensure compliance with the new guideline once it is released.

Program / projects required
It is increasingly an expectation that businesses of the size and nature of SA Power Networks will possess an accredited an Environmental Management System (EMS) accredited to the ISO 14001 standard, EMS. A certified EMS is an extremely effective way to rigorously and efficiently monitor, mitigate and manage environmental risks associated with business operations.

Work has commenced in 2014/15 to obtain accreditation for the business. To obtain and (importantly) maintain the full accreditation of the organisation's EMS, to be able to meet the most recent law changes which will impact our operations from 2015 and to ensure we have sufficient resources to meet the expected continued evolution of environmental laws and regulations we forecast the need for an additional two environmental advisors to be employed.

During the next RCP we fully expect there will be a need to implement additional processes and mitigation measures to investigate, monitor and reduce the risk of environmental damage caused by our infrastructure and operating activities.

Costing Methodology

The increase in operating expenditure is based on an additional two Environmental Advisors at an equivalent pay of grade 7. This is additional resources to meet new initiatives and costs have not been incurred in our base year in relation to any activity which is covered by the new initiative. Consequently, there is no duplication of costs associated with this in regard to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	0.165	**0.165**
Materials	N/A	N/A	N/A	N/A	-	**-**
Services	N/A	N/A	N/A	N/A	-	**-**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**0.165**	**0.165**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.130	0.260	0.260	0.260	0.260	**1.170**
Materials	0.000	0.000	0.000	0.000	0.000	**0.000**
Services	0.052	0.052	0.052	0.052	0.052	**0.260**
Total	**0.182**	**0.312**	**0.312**	**0.312**	**0.312**	**1.430**

Options Analysis

Option 1 – Business as Usual (Do Nothing)

As existing Environment Branch resources are fully utilised SA Power Networks would not have sufficient resources to meet environmental regulatory changes that are expected to occur in the next RCP. The potential (and likely) risks are:

- Increased numbers of reportable incidents, and possible fines and penalties as a consequence of these incidents/breaches of legislation;
- Increased costs associated with the clean-up post environmental incident;

- Increased costs associated with the ongoing assessment, management and remediation of site/groundwater contamination associated with environmental incidents and unidentified current/historical pollution;
- Difficulties with obtaining and maintaining reasonably priced insurance cover; and
- Increased number of non-compliances / non-conformances.

Option 2 – Obtain EMS accreditation and Engage additional Resources
An independent audit of our environmental governance processes (*Internal audit of environmental governance*, KPMG, December 2012) noted the risk of not appropriately resourcing the environmental management function of the business. A gap analysis has subsequently been undertaken by an independent environmental management consultant (*SA Power Networks: Preliminary Review of Environmental Resources*, EnviroManagement, September 2013) and recommended the appointment of an additional two environmental staff to be embedded in the business.

SA Power Networks considers that, consistent with the independent recommendations, recent regulatory changes and increased community expectations with respect to managing environmental impacts of the business together with the likely changes in the next RCP require the addition of two staff members in the Environment Branch. The two Options below outline the costs and implications associated with the resourcing of the Environment Branch.

Option 3 - Additional Resources
Additional resources in the Environment Branch will significantly mitigate the risks described above in option1. In addition, extra resources will enable the Environment Branch to undertake the additional auditing and training associated with the regulatory changes, specifically:

- **Auditing:** An important element of the Environmental Audit 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.
- We have determined that the avoidance/minimisation of the costs associated with a "reactionary" approach to oil filled asset failures, including emergency response, clean up and possible EPA penalties, provides better longer term outcomes for consumers.
- **Training**: The legislative and regulatory changes require additional and updated training packages to be developed and delivered across the business. This is a significant task given the size and dispersed nature of the organisation. SA Power Networks needs to be able to provide evidence of up-to-date training records as part of the EMS certification process and as a precaution in the event that an incident caused serious environmental harm.

Alignment with NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Prudent and efficient resourcing to comply with these new regulatory obligations will support our ability to meet and manage demand for SCS.
Comply with all applicable regulatory obligations or requirements	As detailed above, SA Power Networks is required to comply with a number of environmental obligations and is committed to preventing or minimising pollution and other adverse impacts on the environment.
Maintain safety of the distribution system	Prudent and efficient resourcing to comply with these new regulatory obligations will support our ability to maintain the safety of the distribution system.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach results in the lowest cost to consumers in the long term to comply with this obligation.
Cost that a prudent operator would require to achieve the objectives	Our approach reflects the cost a prudent operator would incur given that SA Power Networks must comply with this requirement.
Realistic expectation of demand and cost inputs required to achieve the objectives	Our supporting documentation demonstrates that our proposed expenditure meets this criterion.

Supporting Documentation

- Supporting Document 21.28 – KPMG: Internal audit of Environmental Governance Report December 2012
- Supporting Document 21.29 – SA Power Networks: Preliminary Review of Environmental Resources September 2013

2. Impacts of Proposed Capital Expenditure Program

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 interactions 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 forecasts.

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.

Consideration of opex trade-off available from capital expenditure
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 trade-off relating to the increased asset replacement program in the 2015-20 RCP. 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 2015-20 RCP.

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 IT portfolio investment. The IT portfolio investment will also generate $36.8 million of avoided costs (June 15 $), that is, additional (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.

Table 6 summarises the capex/opex interaction. The subsequent sections provide details of the individual step changes.

Table 6: Capex/opex interaction step changes SCS 2015-20

June 2015 ($m)	2015/16	2016/17	2017/18	2018/19	2019/20	Totals
Information Technology	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	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**

2.1. Information Technology

Reference	
Opex Chapter Reference	21.6.2
Expenditure Category(s)	Information Technology
Regulatory Driver(s)	Changes to Regulatory Environment, Operating Environment, and Capex/Opex Linkage
Forecast: 2015-2020 (June 15 $)	$43.9m

The additional operating expenditure (**opex**) in IT is associated with the proposed IT capital investment program which in turn is driven by external factors such as changes in applicable regulatory obligations or requirements, concerns raised by electricity consumers together with changes in customer expectations and preferences, and technology developments. The additional IT operating expenditure is required for the ongoing maintenance and support of the systems and infrastructure to be implemented as a result of the IT capital investment program. As detailed in the Proposal, significant prudent and efficient benefits will be realised in other areas of the business as a result of the IT investment.

Business cases have been developed for all IT initiatives in order to justify the investment and ensure the most prudent and efficient option is selected in each case. Each business case contains:

- detailed cost estimates;
- cost-benefit analyses;
- options analyses;
- an explanation of how the preferred option achieves NER expenditure objectives;
- an explanation of how the proposed expenditure reflects the NER expenditure criteria; and
- the justification for the preferred option based on the AER Expenditure Forecast Assessment Guidelines.

The business cases were approved by key business stakeholders following a governance process aligned with the standard SA Power Networks' capital expenditure evaluation procedures.

Description of the Change

The business cases have been classified according to their primary change drivers based on the following definitions:

Table 7: Business Driver Classification

Driver	Description
Business Drivers	
Maintain current levels of service	Business cases primarily associated with significant system replacements or upgrades to manage the risk to current services. There are some benefits associated with these business cases however the primary focus is that of "replacement" and "upgrading" to maintain service rather than a change in capability.

Driver	Description
Compliance	Business cases primarily associated with achieving regulatory or legal compliance and compliance reporting including substantial corporate risk management. The business cases are predominantly associated with the refresh of the SAP environment and enabling an integrated approach to data collection and analysis. Benefits for business cases in this category are predominantly cost avoidance.
Customer	Business cases primarily associated with expected developments in customer services. These are primarily developments associated with expected changes in the electricity industry such as contestable metering and customer information demands. Benefits for business cases in this category are predominantly associated with taking reasonable steps to adhere to expected changes in market rules, customer responses to those changes and changing customer expectations.
Cost Efficiency	Business cases primarily associated with improving the effectiveness and efficiency of SA Power Networks' services. There are cost reduction and/or cost avoidance benefits associated with these business cases.
Regulatory Drivers	
Regulatory Environment	Step changes that are required to comply with our regulatory, legal or compliance obligations
Operating Environment	Step changes that are required to respond to changes in our business operating environment, changes to what is accepted good industry practice and/or changes in the IT environment, technology changes, etc.
Capex/Opex Linkage	Step changes that are primarily due to a capital /operating expenditure linkage. This maybe either an increase or decrease in operating costs arising from proposed capital investments.

What our stakeholders and customers have said to us

Our Customer Engagement Program confirmed that:

- customers have new expectations about how and when we communicate with them and they want more information about the electricity industry;
- 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;
- customers want more choice in how they interact with us;
- customers increasingly value self-service technologies and access to information and services wherever they are;
- 61% of customers surveyed said we should be proactive and responsive, and continue to improve our interactions with them;
- customers support SA Power Networks upgrading the network to allow two-way flows and enable the increasing uptake of new technologies;
- customers support the phased introduction of socially equitable cost-reflective pricing strategies;
- 78% of customers surveyed supported the installation of smart meters to measure and manage electricity usage;
- customers clearly expressed a need for education on new technologies and changes to the industry;

- customers still value contact centre services; and
- raising community awareness through engagement, education and partnerships is essential.

Timing of the Change
Project timing is detailed in the respective business cases, refer to the Information Technology (IT) Document Map at Attachment 20.38.

Costing Methodology/Build Up
Project costs are detailed in the respective business cases, refer to the Information Technology (IT) Document Map at Attachment 20.38.

No double counting of opex (eg output/scale)
Costs shown in the above projects are incremental to those incurred in the base year and additional to normal output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	1.079	**1.079**
Materials	N/A	N/A	N/A	N/A	0.038	**0.038**
Services	N/A	N/A	N/A	N/A	0.757	**0.757**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**1.874**	**1.874**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	2.768	5.243	5.398	3.978	3.272	**20.659**
Materials	0.131	0.363	0.385	0.312	0.282	**1.473**
Services	3.611	5.603	5.565	3.867	3.121	**21.767**
Total	**6.510**	**11.209**	**11.348**	**8.157**	**6.675**	**43.899**

Table 8 below provides details of the IT step changes with reference to the related business case, as well as costs and business and regulatory drivers.

Table 8: The breakdown of the IT Opex step changes over the 2015-2020 RCP by business system, the primary NER operating expenditure objectives, the primary business driver(s) and the primary regulatory driver(s). The business systems are grouped by the SA Power Networks' strategic focus areas. All costs are in June 2015 $ million.

Business Case	Description	Net opex step change[15], $m	Primary NER objectives	Business Driver(s)	Regulatory Driver(s)	Regulatory Driver(s) detail
Energised and responsive customer service						
BC01- CIS and CRM	Replace legacy billing and customer related systems and consolidate for a single view of a customer	6.873	6.5.6(a)(2) & 6.5.6 (a)(4)	Maintain current levels of service Customer	Operating Environment	• Lifecycle stage of one of our major systems - end of life billing system • Ensuring safety of customers eg life support
BC02a – Customer Facing Technology	Refresh and consolidate the customer-facing web based systems and enable customers to get their information in a single view	1.865	6.5.6(a)(2) & 6.5.6 (a)(4)	Customer	Operating Environment	• Reasonable steps to provide communication channels and information that customers have advised they expect
BC02 – Customer Call Management System Replacement	Replace the legacy Customer Contact Centre call management system	1.199	6.5.6(a)(2) & 6.5.6 (a)(4)	Maintain current levels of service	Operating Environment	• End of life call management system

[15] Net of benefits

Business Case	Description	Net opex step change[15], $m	Primary NER objectives	Business Driver(s)	Regulatory Driver(s)	Regulatory Driver(s) detail
Excellence in Asset Management and Delivery of Services						
BC05b – Project, Program and Portfolio Management	Refresh and extend the enterprise-wide capabilities to view and manage all components of portfolios, programs and projects (i.e. scheduling, resource capacity planning)	2.870	6.5.6(a)(2) & 6.5.6 (a)(4)	Cost Efficiency	Operating Environment	• SA Power Networks business departments (eg Field Services, Network Management) require more efficient systems and processes to avoid cost increases associated with the increased volume of asset replacement work that is forecasted for the 2015-20 RCP
BC03 – Enterprise Asset Management	Refresh, consolidate and enhance capabilities into an integrated enterprise approach to asset management, including vegetation management and enabling RIN Reporting compliance	(5.529)	6.5.6(a)(2) & 6.5.6 (a)(4)	Compliance	Regulatory Environment	• Foundation for RIN reporting
BC16 – Field Force Mobility	Significantly enhance existing field mobility capabilities	1.516	6.5.6(a)(2) & 6.5.6 (a)(4)	Cost Efficiency	Operating Environment	• SA Power Networks business departments (eg Field Services, Network Management) require more efficient systems and processes to maintain efficiency levels with the increased volume of asset replacement work forecast for the 2015-20 RCP • Greater compliance reporting requirements around safety

Business Case	Description	Net opex step change[15], $m	Primary NER objectives	Business Driver(s)	Regulatory Driver(s)	Regulatory Driver(s) detail
BC10 – Intelligent Design Management System	Consolidate design tools and implement a standardised design tool and processes	(3.163)	6.5.6(a)(2) & 6.5.6 (a)(4)	Cost Efficiency Compliance	Operating Environment	• Greater compliance and reporting requirements around safety in design
BC05a – Supply Chain	Enable the visibility and management of inventory across depots and warehouses. Extend our analytics and supplier management capabilities	(4.356)	6.5.6(a)(2) & 6.5.6 (a)(4)	Cost Efficiency	Operating Environment	• SA Power Networks requires improved inventory usage to reduce costs
Investing in our People, Assets and Systems						
BC26 – Enterprise Information Security	Foundation enterprise security control capabilities	10.190	6.5.6(a)(2) & 6.5.6 (a)(4)	Compliance	Regulatory Environment Operating Environment	• New Privacy laws • Increased risk of cyber attacks
BC14 – Enterprise Mobility	Consolidate and extend our mobility management and development platforms and approaches	5.912	6.5.6(a)(2) & 6.5.6 (a)(4)	Cost Efficiency	Operating Environment	• Foundation for the Asset Management, Field Force Mobility and interaction with customers and vendors
BC29 – IT Management and Operations	Replace our legacy IT Service Desk and Asset management system and refresh the management processes	2.347	6.5.6(a)(2) & 6.5.6 (a)(4)	Maintain current levels of service Compliance	Operating Environment	• Lifecycle – end of life Service Desk Management System • Support new IT Operating model • Compliance with the Asset Management Policies for IT assets

Business Case	Description	Net opex step change[15], $m	Primary NER objectives	Business Driver(s)	Regulatory Driver(s)	Regulatory Driver(s) detail
Business Foundations						
BC11 – People and Culture Improvements (HR Systems)	Consolidate and upgrade the existing HR systems to provide a single view of employees and extend to provide additional capabilities required for managing employees and skills	0.830	6.5.6(a)(2) & 6.5.6 (a)(4)	Compliance Maintain current levels of service	Regulatory Environment Operating Environment	• Foundation for the RIN reporting and the asset management improvements • Improved time entry to enable accurate calculation of the cost of assets • Compliance with the skills and training accreditation requirements
BC04 – Financial Management	Upgrade and extend the current financial management systems for compliance and capabilities (ie existing General Ledger, Fixed Asset register)	1.755	6.5.6(a)(2) & 6.5.6 (a)(4)	Compliance	Regulatory Environment	• Foundation for the RIN reporting and the asset management improvements
BC31 – Governance, Risk, Regulation and Compliance	Upgrade and consolidate the existing systems to deliver an enterprise wide, integrated solution to manage governance, risk and compliance processes	0.470	6.5.6(a)(2) & 6.5.6 (a)(4)	Compliance	Regulatory Environment	• Enable timely Harmonisation legislation and other regulatory and legal compliance reporting and avoid costs associated with manual reporting

Business Case	Description	Net opex step change[15], $m	Primary NER objectives	Business Driver(s)	Regulatory Driver(s)	Regulatory Driver(s) detail
Enterprise Enabling Technologies						
BC18 - Enterprise Integration	Simplify our enterprise technical capabilities for integration for data and systems	6.173	6.5.6(a)(2) & 6.5.6 (a)(4)	Maintain current levels of service	Capex/Opex Linkage Change in Operating Environment	• Minimise the future Capex costs associated with building or changing 'point to point' integration solutions • Support the transition to the 'end to end' business process model from siloed functionality
BC17 – Data Centre Consolidation	Rationalisation of data centres, increase good practice disaster recovery and governance practices	4.446	6.5.6(a)(2) & 6.5.6 (a)(4)	Maintain current levels of service	Change in Operating Environment Capex/Opex Linkage	• Our data centres are running out of capacity due to increased volumes of data and the increased portfolio of business systems and supporting infrastructure
BC22 – Data Management	Implement a standard foundation Data Management toolsets (ie Enterprise, Quality, Lifecycle)	2.830	6.5.6(a)(2) & 6.5.6 (a)(4)	Compliance Customer	Change in Regulatory Environment	• Foundation for RIN reporting • Compliance with Privacy law • SA Power Networks' business departments, our customers and regulatory bodies require accurate information, more of it, and in a timelier manner
BC12a – Unified Communications	Upgrade the legacy telephony and business communications system and implement new integrated communications channels	1.088	6.5.6(a)(2) & 6.5.6 (a)(4)	Maintain current levels of service Cost Efficiency	Change in Operating Environment	• Lifecycle – upgrade and extension of the phone business communication system • The extension is required to add video and instant messaging capabilities which will result in cost savings to the business

Business Case	Description	Net opex step change[15], $m	Primary NER objectives	Business Driver(s)	Regulatory Driver(s)	Regulatory Driver(s) detail
BC09 – SAP Foundation	Refresh and upgrade the SAP hardware platform (incl Oracle database systems and User Interface for ERP system)	2.412	6.5.6(a)(2) & 6.5.6 (a)(4)	Maintain current levels of service	Change in Operating Environment	• Lifecycle stage of our ERP system – major refresh
BC07 – Enterprise Architecture Tools	Enterprise Architecture repository based toolset	1.839	6.5.6(a)(2) & 6.5.6 (a)(4)	Compliance	Change in Operating Environment	• Foundation toolset for enabling the management of the 'end to end' enterprise business processes
BC24 – Enterprise Information Management	Implement a standard foundation to enable efficient management of documents, records and web content	1.607	6.5.6(a)(2) & 6.5.6 (a)(4)	Compliance	Change in Regulatory Environment	• Foundation for RIN reporting • SA Power Networks' business departments, our customers and regulatory bodies require accurate information, more of it, and in a timelier manner
BC21 – Business Intelligence Enablement	Upgrade our technical capabilities to enable robust business, customer and regulatory reporting including data, analytics and information management	0.728	6.5.6(a)(2) & 6.5.6 (a)(4)	Compliance	Change in Regulatory Environment	• Foundation for RIN reporting, vegetation management reporting, customer service standards and legal reporting

The above table summarises the opex step changes that accompany the series of non-recurrent IT capex investments that form a foundational part of our Proposal. To assist the reader in appreciating the context of this IT program, and its far-reaching implications for our business, our customers and the AER, we provide an edited explanation of our strategy to implement 'optimal integration of our technologies and systems', from Chapter 16 of our Proposal:

Our Proposal includes many initiatives which require investment in systems and technologies to enable us to meet our regulatory obligations and requirements, and to enable delivery of services and 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. These supporting plans include our Customer Service Technology Plan (Attachment 14.1) and our Customer Data Quality Plan (Attachment 16.1).

At the heart of these evolving regulatory requirements and customer expectations, 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.

In Chapter 14 of the Proposal, 'Serving customers now and in the future', we discuss how the current technologies in place to provide these capabilities are ageing, disparate and do not provide the flexibility required to support the provision of services, customer requirements, metering changes and billing solutions into the future, and must therefore 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 Regulatory Investment Plan 2014-20'.

We have also highlighted the continued investment required in our operations systems (SCADA & ADMS) and our telecommunications platforms.

Alignment with the NER objectives and criteria

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.

Consolidation of our 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 the new regulatory reporting purposes, nor have they been consistently built with end to end business processes in mind. Historically, systems have been internally built 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 or 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 and business agility, as well as error and duplication reductions, and provide prudent and efficient 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 efficient uplift in the way it manages the entire asset lifecycle, maximise asset productivity and ensure adherence with 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 reliance on 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 Network grows richer in data, the need for more advanced data and information handling capabilities arises. There has been a growing demand 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 prudent, cost effective and robust solution to support the business now and into the future (refer Proposal Attachment 16.2).

The Step changes outlined above arise from the ongoing operational and security operating costs that will arise when our program of investment to update our business systems and IT infrastructure is implemented. These costs include a range of expenditure such as licence fees, security and IT operational resources, amongst others. Further details are provided in the respective business cases.

Supporting documentation

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment - 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 – SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Attachment 14.1 – SA Power Networks: Customer (Service) Technology Plan 2014-2024
- Attachment 16.1 – SA Power Networks: Customer Data Quality Plan 2015-2020
- Attachment 20.28 – SA Power Networks: Information Technology (IT) Document Reference Map

2.2. Telecommunications

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2.2.2 Carrier costs, radio licensing and planning

Reference	
Opex Chapter Reference	21.6.2
Expenditure Category(s)	DA-8 Network Telephony
Regulatory Driver(s)	Change in Operating Environment
Forecast: 2015-2020 (June 15 $)	$5.1m

Category Function Overview
There are three distinct areas covered by this step change:

Telecommunications Carrier costs - $2.3M across the 2015-20 RCP
SA Power Networks is in the process of undergoing major change within a number of areas across the business that will see an increase in expenditure on links and services provided by carriers such as Telstra and the Nextgen Group.

This increase is driven by a move towards intelligent networks and network automation resulting in a rapid increase in connected devices of 46% over the 2015-20 RCP in areas such as:

- SCADA to substations, grid devices, and asset monitoring (transformers, switches etc); and
- corporate data requirements for depots and data centres.

Radio Licensing costs - $0.7M across the 2015-20 RCP
For SA Power Networks' telecommunications group to support many of the strategies across the business, there will be a significant increase in services due to a move towards intelligent networks and network automation resulting in a rapid increase in connected devices of 46% over the 2015-20 RCP. This is expected to be deployed by a mixture of private and public carrier solutions. In order to support the private communications solutions there is a need to increase the number of radio licences we currently have with the Australian Communications & Media Authority (**ACMA** - the regulatory body).

Network Planning costs - $2.1M across the 2015-20 RCP
Due to the increased focus on communications enabled devices, there is a need to increase resourcing within the telecommunications planning area of SA Power Networks to cope with the increased work load and complexity within the network. Areas of increased focus are; network security, network planning and asset management. The key areas of focus for opex are the security and asset management functions.

Categories 1 and 2 above are referenced below together, as many of the drivers are similar and the method of delivery via either private radio solutions or telecommunications carriers will be based on service requirements such as reliability, latency (ie time for signals to be transmitted) and cost.

Description of the Change

This step change is described under the following sub-headings:

Carrier Costs and Radio Licensing (Smart Devices)

With the increased number of forecast intelligent devices in the network, there will be a requirement to manage and transport the additional data that is presented. This will require:

- an uplift in telecommunication 3G and 4G services to support extra SCADA devices – as outlined in the SCADA expansion strategy;
- inter office and depot data carriage; and
- additional radio services that will require licensing.

It is anticipated that a mixture of NBN, carrier based 3G/4G services and private radio will be required to deliver regional and rural Substation SCADA and (Quality of Supply (**QoS**)) Monitoring Strategies. This is identified in the 2013-2025 Operational Telecommunications Strategy, refer Supporting Document 21.17. Telstra service costs will replace the NBN service cost if the latter is unachievable. Expenditure is estimated at $1.02m.

Included in this opex model is $0.25m pa from 2015/16 to provide a Third Party Carrier data link to a Data Centre or “Cloud” in line with IT Department data centre and Network foundation strategies.

The costs are based on the Operational Telecommunications Strategy and other network strategies that show significant growth in connected Smart Grid, Substation SCADA and QoS Monitoring device numbers across the distribution network. With the deployment of additional private radio into regional areas where it is economically viable, SA Power Networks would need to acquire radio spectrum. This is contingent on the ACMA granting a spectrum licence during 2014/15. Expenditure is estimated at $0.66m.

Network Telecommunications Planning

There are two clear drivers for an increase in resourcing within the Telecommunications Planning area:

- Security within the Operational Technology (**OT**) area is becoming a significant focus both within SA Power Networks and throughout the industry. There are many drivers such as network migration towards internet protocol (**IP**) technology and a greater threat of intrusion.
- With the increased number of devices planned to be added to the network there will be a requirement to increase FTE numbers to cater for the planning and asset management function to ensure a robust and reliable network is maintained.

This is based on our Operational Telecommunications Strategy and other network strategies such as Low Voltage Monitoring, expansion of Smart Grid, Substation SCADA and QoS Monitoring and cyber security initiatives. All of these strategies will require a significant growth in connected device numbers across the distribution network.

Timing of the Change

The proposed increase in FTEs is:

1. (1) x FTE Security function (additional to existing contractors) in 2015/16.
2. (1) x FTE Asset Management (additional to existing contractors) in 2016/17.
3. (1) x FTE Planning Engineer (additional to existing contractors) in 2017/18.

Costing Methodology/Build Up
Costs have been developed based on current service and / or resourcing costs and extrapolated based on supporting strategies such as the Low Voltage Monitoring, expansion of Smart Grid, Substation SCADA and QoS Monitoring, cyber security, IT Data Centre and IT Network foundation initiatives.

Initial steps are primarily due to higher cost services such as interstate links to support the interstate Disaster Recovery (**DR**) Data Centre recommendation, with a more gradual increase in other services and radio licensing.

Telecommunications Carrier costs
Estimates are based on Substation SCADA expansion, QoS monitoring, Smart Grid applications and Corporate IT strategies.

Radio Licensing
The estimate is based on the known connected devices today and the Operational Telecommunications Strategy and other network strategies that show significant growth in connected device numbers across the distribution network in the 2015 to 20 period.

Both the Telecommunications Carrier Costs and the Radio Licensing Costs are based on the requirements to support business strategies including SCADA to all substations, LV monitoring and Corporate IT.

Planning
The estimate is based on the Operational Telecommunications Strategy 2013 to 2015 and other network strategies such as Low Voltage monitoring, expansion of SCADA to additional substations and cyber security imitative. All of these strategies will require a significant growth in connected device numbers across the distribution network. Security requirements are based on greater cyber security threats and the substantial penetration of IP enabled services within the OT environment.

No double counting of opex (eg output/scale)
The above increases in costs relate to expansion of technologies and strategies to meet future needs. It is incremental to costs incurred in the base year and additional to normal output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	N/A
Materials	N/A	N/A	N/A	N/A	N/A	N/A
Services	N/A	N/A	N/A	N/A	N/A	N/A
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.176	0.351	0.527	0.527	0.527	**2.108**
Materials	-	-	-	-	-	**-**
Services	0.344	0.602	0.672	0.692	0.713	**3.023**
Total	**0.520**	**0.953**	**1.199**	**1.219**	**1.240**	**5.131**

Alignment with the NER expenditure objectives and criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	In order to continue to meet or manage the expected demand for standard control services in the changing operating environment outlined above, it is essential that SA Power Networks has the necessary communications systems in place.
Comply with all applicable regulatory obligations or requirements	The proposed telecommunications and resourcing requirements are required if we are to meet our ESCoSA service standards and to otherwise manage risk and network performance in a manner that will enable us to meet a range of other regulatory obligations.
Maintain safety of the distribution system	Appropriate and up to date communications systems and an appropriately resourced telecommunications planning area are fundamental requirements if we are to ensure the safety of our network (including from the ever increasing threat of cyber attacks and IP penetration) and that of the public.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach will deliver the optimum outcome for customers and the business at the lowest cost.
Cost that a prudent operator would require to achieve the objectives	The proposed mixture of telecommunication mediums, together with the additional planning resources, represents the best course of action.
Realistic expectation of demand and cost inputs required to achieve the objectives	Our supporting documentation demonstrates that our proposed expenditure meets this criterion.

Supporting Documentation

- Attachment 7.4 – SA Power Networks: Distribution System Planning (AMP 1.1.01)
- Attachment 13.1 – SA Power Networks: A Smarter Network Strategy 2014-2025
- Attachment 16.2 – EY: SA Power Networks IT Data Centre Strategy June 2013
- Supporting Document 20.102 – SA Power Networks: Suite of IT Business Cases (remaining)
- Supporting Document 20.103 – SA Power Networks: Suite of Asset Management Plans (AMP 2.1.02)
- Supporting Document 21.17 - SA Power Networks, Operational Telecommunications Strategy 2013 to 2015

2.2.3 Network Management Centre (TNOC)

Proposal Section	21.6.2
SEM Category(s)	DA-8 Network Telephony
Regulatory Driver(s)	Change in Operating Environment
Forecast: 2015-2020 (June 15 $)	$3.6m

Category Function Overview
SA Power Networks operates a Telecommunications Network Operations Centre (**TNOC**) to manage the extensive telecommunications infrastructure utilised for the delivery of essential services such as SCADA, Telecommunications Protection (66kV substation protection services), Operational Services Wide Area Network (**OPSWAN**), site environmental management, voice and other substation data services.

SA Power Networks has forecast a significant expansion in its essential telecommunications functions between 2015 and 2025 with the move towards intelligent networks, an expanded SCADA network, Quality Of Supply (**QoS**) transformed monitoring and network automation, resulting in a rapid increase in the number of connected devices in the order of 46% across the State over the 2015-20 RCP for SCADA, and asset metering to meet regulated service standards and service quality.

SA Power Networks has forecast a higher risk in relation to possible cyber security attacks on critical infrastructure, and we have been improving our understanding, processes and governance as a way of managing this risk. Our processes have been developed in line with the relevant international standard (NERC-CIP, IEC 62351), the minimum security standard now being considered as 'good industry practice' for critical infrastructure.

A Telecommunications Network Operations Strategy was developed for us by DNV-GL, refer Supporting Document 21.56. This strategy sets out a future technology roadmap and identifies, at a high level, the need to evolve the TNOC Function.

In order for SA Power Networks to meet the expectations outlined in clause 6.5.6 (a) of the NER it is essential that SA Power Networks maintains its telecommunications network to meet required service level standards and regulated protection safety standards across the business. Critical services such as Tele-Protection and SCADA are paramount to the following operating expenditure objectives:

1. to meet or manage the expected demand for standard control services (**SCS**) over that period;
2. to comply with all applicable regulatory obligations or requirements associated with the provision of SCS; and
3. to maintain the safety of the distribution system through the supply of SCS.

Description of the Change
There is a need to significantly increase the resources within the TNOC over the next 10 years with the majority occurring during the 2015-20 RCP.

The challenges facing the TNOC are significant and include:

- meeting changing safety requirements;
- mitigating risks of cyber-attack with a pro-active approach to security;
- developing resources with skills in new emerging communication technologies;
- ensuring there are sufficient Network Management Officers to cope with growing numbers of devices;
- creating succession plans and cross skilling to minimise the risk of an ageing workforce;
- delivering communication services against more demanding customer and business expectations; and
- maintaining a strong organisational culture whilst undergoing significant change.

There are three key drivers which are seen as having the most immediate impact:

- Increased safety focus in line with recent Work Health and Safety harmonisation legislation which has in turn been reflected in SA Power Networks' safety directives to meet these changes. The impact of this is estimated at 1.3 additional FTE.
- The establishment of a dedicated security role that will provide a consistent approach to security across all technologies. The telecommunications network is an enabler for the delivery of essential services such as Tele-Protection, SCADA and OPSWAN within the Operational technology (OT) environment and faces an ever increasing threat from external cyber attacks. The impact of this is 1 additional FTE.
- The establishment of a helpdesk as a single point of contact for both planned and unplanned outages and restoration, records management, fault recording and tracking. The impact of this is 1 additional FTE.

Timing of the Change
The intention is for up to 7 FTEs to be employed by 2024, with 6 of these to be added by 2020. The rate of expansion will be reviewed in line with work load increases during that period. The period to 2020 is heavily weighted due to the requirement for several urgent roles to address areas of increased pressure from work health and safety reforms and increased focus on cyber security.

Costing Methodology/Build Up
SA Power Networks engaged suitably qualified and experienced independent consultants to assist in building up the future operating model and business case to support the need for change.

As mentioned above, there is a need for 7 FTEs to be employed by 2024 with those additional personnel being progressively employed at stages based on continual evaluation of workloads and practices. By 2020, 6 FTEs will have been added.

A detailed staffing model was developed based on the criteria outlined above with extensive consideration given to meeting safety obligations, cyber security threats and practices and good industry network management practices.

No Double counting of opex (eg output/scale)
The drivers of this step change, most notably changing safety requirements and mitigating the risk of cyber attack, are incremental to the current RCP and are additional to normal output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	N/A
Materials	N/A	N/A	N/A	N/A	N/A	N/A
Services	N/A	N/A	N/A	N/A	N/A	N/A
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.382	0.419	0.558	0.698	0.698	**2.755**
Materials	0.052	0.052	0.052	0.052	0.052	**0.260**
Services	0.119	0.119	0.119	0.119	0.119	**0.595**
Total	**0.553**	**0.590**	**0.729**	**0.869**	**0.869**	**3.610**

Options analysis
DNV-GL were engaged to perform a review of the TNOC and provide a recommendation to address some of the current deficiencies and review future work load expectations in line with current business plans and strategies. In arriving at their recommendation they also conducted a review of two other DNSPs to ensure that the SA Power Networks recommendation was in line with industry practice.

Quantification of financial costs and benefits
A detailed staffing model was developed based on the criteria outlined above with extensive consideration given to meeting safety obligations, cyber security threats and practices and good industry network management practices.

Preferred Option
An increase of 7 FTEs to be employed by 2024, with those additional personnel being progressively employed at stages based on continual evaluation of workloads and practices, is required to service the significant expansion in essential telecommunications functions.

Alignment with the NER expenditure objectives and criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	In order to continue to meet or manage the expected demand for standard control services in the changing operating environment outlined above, it is essential that SA Power Networks TNOC is adequately staffed.
Comply with all applicable regulatory obligations or requirements	Having an adequately staffed TNOC is an essential requirement to meet ESCoSA service standards and SA Power Networks' obligations as an essential service provider. It is expected that, with the implementation of the proposed operational model, SA Power Networks will have the resourcing to meet all of its regulatory and safety requirements during the 2015-20 RCP. The telecommunications network is an essential tool in the management of the distribution network. A primary function of the telecommunications network is to deliver services that in turn allow SA Power Networks to meet its regulatory obligations. The types of services carried out on the telecommunications network are: SCADA to substation and intelligent network devices i.e. re-closures & switches; Telecommunications Protection (high speed protection services for the 66kV network); Operations Wide Area Network (**OPSWAN**, which is separate to the Corporate IT Network) for network monitoring; Critical Voice Services; Corporate IT backbone connections between offices, depots and data centres; Call Centre solutions and applications; and NOC voice & radio services.
Maintain safety of the distribution system	An appropriately resourced TNOC is a fundamental requirement if we are to ensure the safety of the public and of our network (including from the increasing risk of possible cyber security attacks on our essential service infrastructure).

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	The efficiency of our proposed actions is supported by the fact that we will not address anything other than the critical requirements and deficiencies unless and until subsequent detailed workload reviews support the addition of further personnel.

Operating Expenditure Criteria	Considerations
Cost that a prudent operator would require to achieve the objectives	The review carried out by DNV-GL, including the benchmark study conducted against other DNSPs, supports the prudency of the proposed expenditure.
Realistic expectation of demand and cost inputs required to achieve the objectives	Our supporting documentation demonstrates that our proposed expenditure meets this criterion.

Supporting Documentation

- Supporting Document 21.17 – SA Power Networks: Operational Telecommunications Strategy 2014-2025
- Supporting Document 21.56 – DNV GL: Telecommunications Networks Operations Strategy
- DNV GL: Telecommunications OSS Requirements Definition and Cost Estimate (available on request)

2.3. Data quality

Reference	
Proposal Section	21.6.2
SEM Category(s)	DA-23 Retail Contestability
Regulatory Driver(s)	Change in Operating Environment
Forecast: 2015-2020 (June 15 $)	$3.9m

Category Function Overview
SA Power Networks' function as a provider of electricity distribution services requires the acquisition, storage and management of immense volumes of data[16] relating to the assets we own and operate, as well as the customers served by those assets.

Regulatory rules, legal obligations and prudent corporate operations require SA Power Networks to translate this vast volume of data into information and knowledge that can be used for decision making, national market operations and form the basis of communication and interaction at all levels – from macro level corporate performance reporting, to detailed connection point information for a small residential customer.

In order for SA Power Networks to obtain the best value from the data that is obtained, and translate it into accurate and meaningful information it must be managed appropriately, in accordance with what is viewed as good practice globally. The appropriate management of SA Power Networks' data feeds into the corporate governance and risk management practices of the organisation and becomes vitally important as SA Power Networks' data volumes incrementally increase overtime.

The Data Management Association (**DAMA**) provides a globally accepted framework and good practice reference for data management. The definition of data management provided in the DAMA Data Management Body of Knowledge (DAMA-DMBOK) is: "*Data management is the development, execution and supervision of plans, policies, programs and practices that control, protect, deliver and enhance the value of data and information assets.*"

Since 2009 SA Power Networks has been working on some of these components of data management for our customer data domain. SA Power Networks has determined customer data to be simply all the data about the customer and the relationships a customer has with our assets, either directly through an agreement for electricity supply from a connection point or indirectly through the situation of SA Power Networks assets on a customer's property. An important element of this definition is the inclusion of the relationships and linkages that exist between a customer and a distribution network asset. It is these relationships that drive the business processes that consume customer data and they are of critical importance to having a high degree of accuracy.

[16] SA Power Networks has 400 zone substations, 72,600 transformers and 723,000 Stobie poles, 834,554 customers and in excess of 1 million meters – all of which have a number of data attributes stored about them. In addition, transactions occur on a daily basis relating to these data attributes, such as 730,000 phone calls, 60,000 customer initiated jobs, 4.5 million meter reads, 200,000 service orders (figures taken from the 2012 SA Power Networks Annual Report and transaction volumes are over the 2012 calendar year). The E&Y Data Centre Strategy for SA Power Networks estimates the organic growth of this information of 25-30% year on year from 2013.

Moving into the 2015-20 RCP SA Power Networks is planning to increase the commitment to improving customer data quality by moving to a holistic, productivity improvement focussed data management system. This will leverage off the work already started on customer data management, and adapt the program to comprehensively cover all aspects of customer data, so it is fit for the purposes intended today and over the course of the 2015-20 RCP.

The commencement of Full Retail Contestability in 2003 brought a large repository of customer information, new business processes and data exchange obligations to SA Power Networks to manage. Over time it became evident that there were shortcomings in the data that affected the outcome of business processes, and ultimately the quality of customer service provided to South Australians and the effectiveness of the SA Power Networks' field workforce.

Throughout the current RCP, SA Power Networks has undertaken a series of data improvement initiatives on a subset of data issues. Also during this time the reliance on the quality of customer data has increased as SA Power Networks has implemented new systems and business processes. Issues with the quality of our customer data are now much more critical to SA Power Networks' daily operations. Thousands[17] of notifications are now issued to customers each month to provide important information about the state of their power supply, either through bulk mail outs or SMS messaging. These notifications rely on the accuracy of postal addresses and phone numbers that SA Power Networks store for each customer. A single error or omission can result in a day of field work being cancelled and a complaint to manage from an unsatisfied customer. These outcomes generate unnecessary costs and inefficiencies for the business that could be avoided if the data was accurate. A program of data quality improvement, which follows on from previous work in the area, has been developed to address the issues with customer data that SA Power Networks is experiencing, and to also put us in good stead for the implementation of future initiatives contained within the SA Power Networks Customer Service Strategy. The data quality improvement program is a key enabler for the delivery of the SA Power Networks Customer Service Strategy and the achievement of our corporate strategic objectives.

Description of the Change

The six focus areas for customer data improvement are:

1. Communicating with our customers.
2. Locating our assets and customers.
3. Managing the connectivity of customers to the distribution network.
4. Providing information between the field and office.
5. Enabling and supporting our future plans.
6. Overarching improvements (including governance, processes and data ownership).

Approach

To develop these focus areas and their initiatives, SA Power Networks has undertaken the following process:

- Identified the core customer functions and business processes undertaken by SA Power Networks and the data that drives them.
- Reviewed data issues raised through various forums since the initiation of the data quality program in 2009.
- Discussed data concerns with key stakeholders.
- Identified the data requirements for SA Power Networks' future improvements.

[17] 24,561 notifications sent to customers affected by planned outages and 26,206 SMS's sent to customers affected by unplanned outages in July 2014.

- Identified best practice data management tools and techniques required to support the customer data improvement initiatives in the business operations.
- Consolidated this information into a series of initiatives designed to meet SA Power Networks' current and ongoing customer data requirements.

Operating Environment

Prior to the commencement of the 2010-15 RCP, SA Power Networks began work on a customer data quality improvement program. The initiation of the program identified a significant volume of data errors that required correction and an investment in resources and supporting technology to do so. Throughout the 2010-15 RCP the resources dedicated to data improvement have been steadily increased as improvement targets have been attained and innovative concepts progressed to normal business operations.

Within this timeframe the environment in which SA Power Networks operates has changed rapidly as technological advances have been adopted by our customers. As people embrace new technology their expectations also shift in line with the functions enhanced by that technology. It is now expected that organisations, like SA Power Networks that provide an essential service to the whole community, are able to meet these expectations for interactions and the desire for accurate and relevant information.

To meet the changing needs of the community SA Power Networks has implemented a number of new services during the 2010-15 RCP that leverage off adopted technological advances. Hybrid web applications using Google Maps overlayed with our public lighting infrastructure, SMS of unplanned outage updates to subscribers and mass mailing of planned outage notifications, are all examples of how SA Power Networks is embracing new technology and the efficiencies and customer service benefits that result. However, as these business processes become increasingly automated, the underlying data in the system becomes exposed, with any deficiencies reducing the effectiveness of the automated processes and creating the need for error and complaint management processes to be implemented. To reduce time spent on the management of these errors and issues, SA Power Networks needs to invest in the underlying datasets that drive the processes by correcting, enriching and managing the data.

Additionally, significant effort has been invested in obtaining meter GPS data during the 2010-15 RCP for many of SA Power Networks' meters (over 700,000 GPS coordinates collected to date[18]), which now requires quality controls to be implemented to manage this information asset. The meter GPS data has proven to be a valuable asset to SA Power Networks' business operations by assisting office based staff to improve property data quality, plan and schedule work, and locate customers when performing field work, thereby realising greater efficiencies. New business processes have been put in place to receive continual updates of this information as field operations are carried out, resulting in data updates from numerous sources. To ensure this information continues to remain a valuable resource for SA Power Networks, an investment is required to be made to manage the ongoing quality of this data.

The work required to manage and improve customer data quality at SA Power Networks has been developed into a program of work that tackles our data quality issues from a number of angles. The program of work builds on the investment SA Power Networks has made during the 2010-15 RCP in people and technology by adding new capabilities for data cleansing and enrichment, and increasing coverage to all components of the customer data domain. In conjunction with increased capabilities,

[18] As of 5 September 2014

SA Power Networks will also improve the policies, procedures and work practices in line with the standards of a good data management practice.

What our stakeholders and customers have said to us

- customers have new expectations about how and when we communicate with them;
- 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;
- customers want more choice in how they interact with us;
- customers increasingly value self-service technologies and access to information and services wherever they are;
- 61% of customers surveyed said we should be proactive and responsive, and continue to improve our interactions with them;
- customers support the phased introduction of socially equitable cost-reflective pricing strategies; and
- 78% of customers surveyed supported the installation of smart meters to measure and manage electricity usage.

Timing of the Change

The first two years of the 2015-2020 RCP include resourcing an increased effort to fast track the improvement of customer property information, as this forms the basis of improvements for other components of customer data. As this effort is nearing completion in Year 2, SA Power Networks will gradually begin to implement the active customer data management business functions across the remaining customer data components, bringing the resourcing commitment to the expected level required to perform this new function on an ongoing basis.

The technology supporting this resourcing effort, SAP Information Steward, has already been implemented by SA Power Networks as a capex project in 2014. This tool provides the data issue identification and tracking capabilities required to analyse all components of our customer data and actively manage them on a daily basis and also includes the ability to build in business rules to cleanse the invalid data.

Costing Methodology/Build Up

Costs are based on an additional 11 resources initially, reducing to 7 during the RCP, as contained in the Customer Data Quality Plan (refer Attachment 16.1). Resources have been costed at internal rates.

No double counting of opex (eg output scale)

This step change relates to the implementation of new data quality initiatives in the 2015-20 RCP. Costs are incremental to the current RCP and are additional to normal output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	N/A
Materials	N/A	N/A	N/A	N/A	N/A	N/A
Services	N/A	N/A	N/A	N/A	N/A	N/A
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	1.046	0.856	0.666	0.666	0.666	**3.930**
Materials	-	-	-	-	-	**-**
Services	-	-	-	-	-	**-**
Total	**1.046**	**0.856**	**0.666**	**0.666**	**0.666**	**3.930**

Options Analysis

Option 1 – Business as Usual (Do Nothing)

The evaluation of the Do Nothing Option forms the baseline for decision making and has been evaluated to understand the risks and impacts associated with maintaining existing 'business as usual' operations. The continuation of 'business as usual' will result in adverse impacts for our customers and the business if this option is adopted.

At SA Power Networks the continuation of 'business as usual' for customer data management involves maintaining the current resourcing and efforts to improve data quality for the customer property datasets, which have been identified as the highest priority issue for resolution. The remaining customer datasets will remain under passive management, leaving a poor foundation of data for customer interactions and business operations.

SA Power Networks will also not be able to take advantage of technology investments, initiated in 2014 for data management and data profiling tools, should the Do Nothing option be selected. The data management activities will continue to occur on an ad hoc basis and utilise manual methods, using best endeavours to attempt to attain the standards expected of good data management practice. SA Power Networks will be able to implement the required policies and procedures for data management as part of continuing 'business as usual', but there will be limited capability to monitor and enforce adherence to those policies and procedures without additional investment in data management.

Since the beginning of 2011 the degradation in quality of a number of key customer datasets relied upon for effective customer interactions has occurred at an elevated rate, in excess of 175% in some cases and exceeding 400% for phone number records[19]. Should this trend continue, even at a reduced rate, SA Power Networks will possess an immense amount of data that is not fit for purpose. The unfit data will have an increasingly negative effect on the business operations of SA Power Networks leading to increased costs through inefficiencies, errors, non-compliance and poor outcomes for customers.

Option 1 – Benefits
There are no benefits associated with the Do Nothing Option.

Option 1 - Dis-benefits
There are a number of dis-benefits associated with the Do Nothing Option:

ID	Dis-benefits	Consequence outcome
DB1	Data is not aligned with the business processes	• Potential for incorrect decisions leading to increased maintenance costs and/or outages • The full benefit of SA Power Network's initiatives will not be realised if the data management systems are not in place to support them.
DB2	Lack of data governance, management and quality processes	• Rapidly deteriorating data quality • Duplication of master data • Incorrect transactions • Lack of business confidence in reporting • Poor data feeding into risk management processes
DB3	Lack of data standards	• Data quality targets cannot be defined and measured • Unable to improve data quality as baseline is not defined
DB4	Not the appropriate focus on data profiling and cleansing	• Poor data quality • Unable to understand the root cause of data issues

[19] At the beginning of 2011 SA Power Networks reported a blank phone number value of 18,784. This same statistic at the end of 2013 recorded a value of 78,395 – an increase of 417%. For the same periods the bad customer name statistic increases from a value of 14,424 to 27,869 – an increase of 193%.

Option 1 – Risks

The risks associated with the Do Nothing Option are:

Risk ID	Risk Description (Risk Line Item)	Consequence Description	Inherent Likelihood	Inherent Consequences	Risk Rating
R01	Data not captured to a level of detail required by the AER	Business must capture data details in alternative applications such as MS Excel leading to data integrity issues and increased audit costs Lead to potential inaccuracies in data leading to lack of business confidence in utilising the data to make informed decisions	Likely (4)	Moderate (3)	HIGH
R02	Data is not aligned with the business processes	Data management decision making is restricted by the lack of quality data that can be relied upon which may result in incorrect decisions and increased maintenance cost and/or outages	Possible (3)	Moderate (3)	MEDIUM (6)
R03	Data cannot be retrieved in a timely manner	Relevant electronic data cannot be produced in a timely manner, resulting in customer complaints and actions, adverse legal rulings, and even punitive damages	Possible (3)	Moderate (3)	MEDIUM (6)
R04	Exception rate in automated processes increases to a level where the automation benefits are completely eroded	Failure rates of automated processes and misdirected information produce administrative overheads so great that the benefits of automation are completely offset by those costs.	Unlikely (2)	Moderate (3)	LOW

Option 2
Implement the proposed data management capabilities for all customer data used by SA Power Networks.

Option 2 consists of SA Power Networks' proposal to implement data management functions across the entire customer data domain, with an expedited improvement to the quality of property addressing data.

The scope of this option includes:

- Implementation of a data governance framework to develop and manage data management policies, procedures, KPI's and accountability for datasets.
- Development and ongoing management of a metadata repository for defining attributes and a source of truth for key data elements.
- Implementation of a range of initiatives to improve data quality through correcting incorrect data, enriching incomplete records with data from third party sources, consolidating duplicate information and actively managing updates to data sourced from national market transactions.
- Expedited improvements to property addressing data quality to enable fast tracking of improvement focus to all aspects of customer data.
- Monitoring the effectiveness of data management policies and procedures and identifying non-compliance.
- Developing a data profiling and cleansing capability to identify particular areas of concern, apply bulk corrections and show progress of improvements over time.
- Actively managing linkage of customer, property and asset data.
- Actively managing updates to meter GPS data.

Option 2 – Benefits
The benefits associated with Option 2 are as follows:

Risk ID	Benefit Type	Benefit	Benefit Effect	Benefit Category
B1	Intangible	Standardised and consistent data to feed into regulatory and operation reporting	Direct	Process Efficiency and Cost reduction
B2	Intangible	Customer data is aligned with the business processes and improved data governance, management and quality processes	Direct	
B3	Intangible	Improved ability to identify customers impacted by a loss of electricity supply and feed accurate customer contact data, customer to asset linkages and property data into unplanned outage operations.	Direct	

Risk ID	Benefit Type	Benefit	Benefit Effect	Benefit Category
B4	Intangible	Increased ability to successfully implement automated processes that consume accurate customer data.	Direct	Process Efficiency and Cost Reduction
B5	Intangible	Improved ability to identify customers impacted by distribution network maintenance or project works and feed accurate customer contact data, customer to asset linkages and property data into planned outage operations.	Direct	
B6	Intangible	Improved ability to identify customers impacted by supply point and metering works and feed accurate customer contact data, customer to asset linkages, GPS location and property data into field operations.	Direct	
B7	Intangible	Improved ability to identify customers making an enquiry or complaint and feed accurate customer contact data and property data into customer service operations.	Direct	
B8	Intangible	Improved ability to associate hazardous conditions relating to a property or customer with field operations to ensure the safety of employees and customers, and the integrity of the environment.	Direct	
B9	Intangible	Appropriate focus on data profiling and cleansing	Direct	Compliance to Regulatory Requirements, Effective Decision Making and Risk Management
B10	Intangible	Improved ability to meet national market requirements to provide accurate data to Australian Energy Market Operator (**AEMO**) and other market participants	Direct	
B11	Intangible	Improved ability to administer Guaranteed Service Level (**GSL**) payments through use of accurate customer contact details and the accurate identification of customers impacted by loss of supply with correct customer to asset linkages.	Direct	

Risk ID	Benefit Type	Benefit	Benefit Effect	Benefit Category
B12	Intangible	Shared understanding of data issues is available to all stakeholders	Direct	Compliance to Regulatory Requirements, Effective Decision Making and Risk Management
B13	Intangible	Improved ability to manage emergency and high risk situations through accurate information about customers impacted and the linkage of the customer to the assets.	Direct	
B14	Intangible	Improved ability to manage risk through better availability of accurate information	Direct	
B15	Intangible	Facilitates data driven decisions and develops greater understanding of our customers and assets	Direct	

Option 2 - Dis-benefits
There are no dis-benefits associated with Option 2.

Option 2 – Risks
The risks associated with Option 2 are as follows:

Risk ID	Risk Description (Risk Line Item)	Consequence Description	Inherent Likelihood	Inherent Consequences	Risk Rating
R01	Data degradation occurs at an accelerated rate compared to historic observations, reducing the effectiveness of data improvements.	The expected benefits to process efficiency and customer service are reduced in magnitude as a result of increased volumes of poor data entering SA Power Networks systems.	Unlikely (2)	Moderate (3)	Low
R02	The need for accurate data for some data types becomes obsolete due to further technological advances	Effort has been spent improving data that is no longer required.	Rare (1)	Moderate (3)	Low

Preferred Option
Option 2 - "Implement the proposed data management capabilities for all customer data used by SA Power Networks" is the preferred solution.

This option has been selected for the following reasons:

- It implements the necessary data management functions in order to achieve operational efficiencies and customer service benefits.
- The option aligns with the strategic objectives of SA Power Networks.
- The level of risk involved for this option is low.
- This option increases the availability of accurate data for informed business decision making.
- This option implements a cost effective response, consistent with good practice globally, to a dynamic environment where the timely delivery of accurate and relevant information is a key to customer satisfaction.

Alignment with the NER expenditure objectives and criteria
Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Obtaining quality data to translate into accurate and meaningful information is an important tool that enables SA Power Networks to meet and manage expected demand for standard control services. Incorrect data generate unnecessary costs and inefficiencies for the business that could be avoided if data was accurate.
Comply with all applicable regulatory obligations or requirements	A range of legal and regulatory rules and obligations require SA Power Networks to translate vast volumes of data that we collect into information and knowledge that can be used for decision making, national market operations and service delivery. We can only meet these obligations and requirements if the data and resulting information is accurate.
Maintain safety of the distribution system	Collection of quality data is a key factor in supporting our ability to maintain the safety of the distribution system.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our proposed approach implements a cost effective response, consistent with good practice globally in a dynamic environment where the timely delivery of accurate and relevant information is essential.
Cost that a prudent operator would require to achieve the objectives	The end to end integration of data will reduce duplication and manual intervention, increase flexibility, and provide a single source of information for customers, assets, work and reporting – outcomes that any prudent operator would take steps to achieve.
Realistic expectation of demand and cost inputs required to achieve the objectives	Our supporting documentation demonstrates that our proposed expenditure meets this criterion.

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 - SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Attachment 16.1 – SA Power Networks: Customer Data Quality Plan 2015-2020

2.4. Substation maintenance – disconnectors

Reference	
Proposal Section	21.6.2
SEM Category(s)	DA-13 Asset Maintenance
Regulatory Driver(s)	Change in Operating Environment
Forecast: 2015-2020 (June 15 $)	$2.4m

Category Function Overview
Over the last two RCPs a significant number of substation disconnectors have been installed. These now need maintenance works to ensure that they can be reliably operated when required for switching.

Substation disconnectors need to be regularly maintained to ensure serviceability. Traditional servicing procedures require the disconnector to be de-energised and isolated which generally means the entire substation will be bypassed or offloaded. Due to the high cost and disruption to customers, this work is often deferred or cancelled resulting in a large maintenance backlog.

Non-maintained disconnectors are likely to seize and will then have a high risk of failure during attempted operation. Historically there have been incidents involving a live HV conductor failing close due to failure of disconnector components. Regular maintenance will minimise this risk.

Non-maintained disconnectors often become inoperable resulting in late cancellation of planned work and subsequent re-scheduling of work with increased limits of isolation for both SA Power Networks and ElectraNet.

Description of the Change
An additional 5 person live line crew will be required to undertake this program of substation disconnector maintenance work.

The total step change adjustment for the 2015-20 RCP is an expenditure increase of $2.430m.

Live line maintenance will avoid the need for bypass arrangements, with corresponding lower maintenance cost per unit, and will avoid the need for substation offloads thereby avoiding planned disruption to customer supply.

Disconnector maintenance backlog is expected to be eliminated after 5 years, reducing opex in the 2020-25 RCP, which will partly offset this opex increase in future years.

What our stakeholders and customers have said to us

- a high level of customer support (88%) for increasing monitoring efforts to monitor the condition of ageing assets and replacing aged assets before they fail;

- a high level of customer support (89%) for upgrading and reinforcing the network where factors such as changing local demand, environment (ie corrosion) and the type of supply to an area (single line of supply);
- stakeholders and customers believe it is important to prioritise preventative maintenance to reduce network risks;
- 88% of customers surveyed were satisfied with their current level of network reliability and have advised that they want current levels of reliability maintained; and
- inspecting, maintaining and upgrading the network was ranked in the top 3 community safety and reliability initiatives by customers in both the workshops and online survey.

Timing of the Change

Maintenance of additional disconnectors will be planned and commence in 2014/15 using bypass arrangements as an interim measure to address the three highest risk sites (approximately 60 disconnectors). The cost of bypass and maintenance work is expected to be approximately $120,000 per site (based on recently completed work).

Costing Methodology/Build Up

Maintenance history and backlog is recorded in SAP. Historically, an average of 112 disconnectors are maintained each year. As 412 disconnectors are due each year in order to meet the 9 year programmed maintenance cycle, that leaves 300 disconnectors overdue every year (given the maintenance average of 112).

Approximately 1,200 job hours are required to maintain 300 disconnectors using the live line method.

Costs are calculated on the basis of 1200hours x 5 people ($66.30/hour + $11.70/Hr O/H).

No double counting of opex (eg scale/output)

This represents an increase in costs to fully maintain substation disconnectors and to reduce safety and operational risks. Costs are incremental to the current RCP and are additional to normal output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	0.360	**0.360**
Materials	N/A	N/A	N/A	N/A	-	**-**
Services	N/A	N/A	N/A	N/A	**-**	**-**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**0.360**	**0.360**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.486	0.486	0.486	0.486	0.486	**2.430**
Materials	-	-	-	-	-	**-**
Services	-	-	-	-	-	**-**
Total	**0.486**	**0.486**	**0.486**	**0.486**	**0.486**	**2.430**

Options Analysis

Several options have been considered to address the risk posed by infrequent maintenance of disconnectors. These options are presented below.

Option 1 – Business as Usual (Do nothing)

This option does not address the identified significant safety and operational risks associated with un-maintained disconnectors.

A do-nothing approach will result in an increasing number of incidents as condition continues to deteriorate.

The inability to accurately assess the condition of these disconnectors and the safety hazards inherent to this particular switchyard construction, make effective management of site risks infeasible. This approach would therefore result in significant ongoing safety, operational and financial risks as well as diminished system security across the distribution network.

Option 2 – Establish a live line crew for maintenance of substation disconnectors

Substation disconnectors need to be regularly maintained to ensure serviceability and safety. Traditional servicing procedures require the disconnector to be de-energised and isolated which generally means the entire substation will be bypassed or offloaded. Due to the high cost and disruption to customers, historically this work has often been deferred or cancelled resulting in a large maintenance backlog.

In many substations it is possible to maintain disconnectors using live line techniques. A jumper cable is used to bridge across the disconnector which can then be operated and lubricated. Electrical contacts can be cleaned and porcelain insulators checked for damage or any sign of fatigue. This method requires a specialised 5 person crew, including safety observers.

Advantages of this option include:

- no disruption of power to customers;
- minimal switching is required; and
- it is the lowest cost option (approximately $35,000 per site).

Option 3 – utilise a bypass arrangement for disconnector maintenance

This is the most expensive option. A bypass arrangement may be used to facilitate maintenance by providing an alternative power supply to customers while the entire substation is de-energised and isolated. This type of work must be planned several months in advance as it generally requires deployment of a mobile substation and a large number of switching operations. With the substation de-energised, all disconnectors within the limits of isolation can be maintained and repaired.

Based on recently completed work at other sites, the average cost to bypass a substation and maintain all disconnectors (approximately 20) is $120,000 per site.

Preferred Option

Option 2, involving establishing a dedicated live line crew is the preferred option for the following reasons:

- no disruption of power to customers;
- minimal switching is required; and
- it is the lowest cost option (approximately $35,000 per site).

Alignment with the NER expenditure objectives and criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	As substation disconnectors need to be regularly maintained to ensure serviceability, this approach is necessary to meet or manage expected demand for standard control services.
Comply with all applicable regulatory obligations or requirements	SA Power Networks has a number of legal obligations to maintain its network assets in a safe operating condition. To do this, we must ensure that our network assets, such as substation disconnectors, are properly maintained.
Maintain safety of the distribution system	As mentioned above, there are a number of safety and operational risks associated with un-maintained disconnectors and doing nothing will result in an increasing number of incidents as condition continues to deteriorate. Accordingly, servicing substation disconnectors in the manner proposed is necessary to maintain the safety of the distribution system.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach of establishing a live line crew for maintenance of substation disconnectors is the least cost option for maintaining those disconnectors.
Cost that a prudent operator would require to achieve the objectives	Our proposed approach represents the best course of action considering available alternatives.
Realistic expectation of demand and cost inputs required to achieve the objectives	Our supporting documentation demonstrates that our proposed expenditure meets this criterion.

Supporting Documentation/Evidence

Implementation of an enhanced maintenance program specifically targeting substation disconnectors is part of the overall strategy to manage the serious safety risks posed by this equipment.

The overall strategy is described in detail in AMP 3.2.17 Substation Air Break Disconnect Switches 2014 to 2025 (refer Attachment 20.6).

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 – SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Attachment 20.6 – SA Power Networks: Asset Management Plans (Inventory)

2.5. Condition monitoring and network planning

Reference	
Opex Chapter Reference	21.6.2
Expenditure Category(s)	DA-6 Operational Asset Management
Regulatory Driver(s)	Change in Operating Environment
Forecast: 2015-2020 (June 15 $)	$1.8m

Category Function Overview
The asset management strategic direction is detailed in AMP 3.01.01 Condition Monitoring & 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, SA Power Networks 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.

Description of the Change
To implement this strategy additional asset management (office based) and field test personnel are required to fulfil the following key steps associated with a mature asset management strategy:

1. Determine appropriate asset and condition data required.
2. Determine and procure required condition monitoring and diagnostic tools.
3. Implement a condition monitoring and diagnostic testing regime.
4. Manage and analyse data.
5. Apply outcomes to asset management strategies (replacement, refurbishment and maintenance).

This condition data capture and processing underpins the basis of the Detailed Asset Management Plans for all substation primary assets. In particular, the implementation of the Condition Based Risk Management (**CBRM**) program for priority assets (which, for substations, are power transformers and high voltage circuit breakers) requires significant increase in condition data.

The total step change adjustment for the 2015-2020 RCP is $1.8m.

What our stakeholders and customers have said to us
Our Customer Engagement Program confirmed that:

- a high level of customer support (88%) for increasing monitoring efforts to monitor the condition of ageing assets and replacing aged assets before they fail;
- a high level of customer support (89%) for upgrading and reinforcing the network where factors such as changing local demand, environment (ie corrosion) and the type of supply to an area (single line of supply);
- stakeholders and customers believe it is important to prioritise preventative maintenance to reduce network risks;

- 88% of customers surveyed were satisfied with their current level of network reliability and have advised that they want current levels of reliability maintained; and
- inspecting, maintaining and upgrading the network was ranked in the top 3 community safety and reliability initiatives by customers in both the workshops and online survey.

Timing of the Change

Over recent years project based contract resources have been utilised to undertake data management tasks, principally related to backlog of asset information and maintenance plans. From commencement of 2015 it is planned to employ a full time resource.

Costing Methodology/Build Up

The cost estimate is based on the following resource mix:

- asset management (office based) – 1 x FTE
  - 1672.5 hours x $91.73 (NP engineer rate $2013) x 1.0337 (June 15 escalation)
- diagnostic testing (field based) – 2696 hours (refer attached spreadsheet)
  - 2696 hours x $83.60 (average labour rate for Field Services engineering, TSW Sub Maintenance & HV Testing) x 1.0337 (June 15 escalation)

No double counting of opex (eg output/scale)

The purchase and implementation of condition monitoring equipment, programs and tools to enable economically efficient management of critical assets is planned for the 2015-20 RCP. Costs are incremental to the current RCP and are additional to normal output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	0.079	**0.079**
Materials	N/A	N/A	N/A	N/A	-	-
Services	N/A	N/A	N/A	N/A	-	-
Total	**N/A**	**N/A**	**N/A**	**N/A**	**0.079**	**0.079**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.211	0.315	0.420	0.420	0.420	**1.786**
Materials	-	-	-	-	-	-
Services	-	-	-	-	-	-
Total	**0.211**	**0.315**	**0.420**	**0.420**	**0.420**	**1.786**

Options Analysis
The asset management strategic direction is detailed in AMP 3.01.01 Condition Monitoring & Life Assessment Methodology.

With the increasing availability of additional and improved asset condition and performance data it is now possible to achieve a more optimised (efficient and prudent) capital expenditure for asset replacements. However, to achieve this it is necessary to have appropriate resource to determine what data is required, capture the data and then process this data (manage and analyse).

Early detection and prevention has proven successful over the last few years in preventing significant plant failures and associated customer outages. However failure trends in certain asset types indicate that additional condition monitoring and analysis is required to prevent an escalation in unplanned outages resulting from plant failure. For example, the 48 year old 11kV circuit breakers at Elizabeth Heights substation, which until recently were performing very well, have failed to operate correctly 3 times over the past year when required to clear a network fault. Additional specialised condition monitoring would most likely have detected the issue and avoided the loss of supply to a large number of customers.

Option 1 – Business as Usual (Do Nothing)
This option is contrary to the business asset management strategic direction (refer Condition Monitoring & Life Assessment Methodology – AMP 3.0.01) and good industry practice where asset maintenance, refurbishment and replacement decisions should be made on the basis of asset condition information rather than purely on age or run to failure.

Disadvantages of this Option are:

- No improvement in optimisation of asset replacement decisions; for many assets this will require decisions to be based predominantly on age.
- Increased adverse customer impact due to unplanned failures.

Option 2 - Additional Resources
This option provides for additional field testing and asset management resources to be introduced to enhance the breadth, detail and quality of asset condition data to allow a more informed assessment and therefore result in optimised decisions with regard to asset replacement and maintenance strategies.

Advantages of this option include:

- Optimised asset replacement expenditure (e.g. deferment of the replacement of one power transformer by 1 year will result in a capex saving of approximately $0.1m ($2m @ 5%)).
- Prevent the increase in unplanned failure outages as the asset fleet ages (e.g. prevention of a feeder circuit breaker failure to trip and subsequent business outage with consequential adverse customer impact of $0.4m (VOLL) per event. (Note: over the last few years this has occurred 5 times at 3 sites).
- Supports the move to an optimised maintenance strategy for substation plant. The historical strategy has many un-synchronised maintenance strategies across the range of substation plant which results in repeat visits and outages at substations over relatively short periods of time. The addition of more detailed and accurate condition and performance data will allow the risks to be more accurately quantified (failure modes and consequences) resulting in an optimised strategy being developed over the 2015-20 RCP. (Note: an example of extending transformer tap-changer maintenance too far resulted in the catastrophic failure of a

12.5MVA transformer, with an approximate replacement cost of $1.2m and significant damage caused to another transformer with a repair cost of approximately $200,000). The expected impact of this, is that some plant will be maintained less frequently and other plant more frequently, but with an overall improvement in maintenance efficiency. Any impact on the opex expenditure is expected to be realised in the 2020-25 RCP.

Preferred Option

Option 2, providing the introduction of additional field testing and asset management resources, is the preferred option, as it:

- optimises asset replacement expenditure;
- prevent the increase in unplanned failure outages as the asset fleet ages; and
- supports the move to an optimised maintenance strategy for substation plant.

Alignment with the NER expenditure objectives and criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Failure to detect and prevent significant plant failures and associated customer outages has the potential to impact SA Power Networks' ability to meet or manage expected demand for standard control services.
Comply with all applicable regulatory obligations or requirements	SA Power Networks has legal obligations to take reasonable steps to maintain our network assets in a safe operating condition. Capturing and processing condition based data to implement the CBRM program for priority assets is an important aspect of being able to meet our regulatory obligations.
Maintain safety of the distribution system	Failure to detect and prevent significant plant failures and associated customer outages has the potential to impact our ability to maintain the safety of the distribution system. The additional field testing and asset management resources are required to minimise the risk of such failures.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach results in the lowest cost to customers and the business over the longer term.
Cost that a prudent operator would require to achieve the objectives	By further implementing a condition/performance risk based replacement strategy for priority assets, we will be able to make and develop prudent decisions and strategies to manage those assets into the future.
Realistic expectation of demand and cost inputs required to achieve the objectives	Our supporting documentation demonstrates that our proposed expenditure meets this criterion.

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 – SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Attachment 9.1 – SA Power Networks: Condition Monitoring and Life Assessment Plan (AMP 3.0.01)

2.6. Flexible load management

Reference	
Proposal Section	21.6.2
SEM Category(s)	DA-18 Demand Management
Regulatory Driver(s)	Change in Operating Environment
Forecast: 2015-2020 (June 15 $)	$1.0m

Category Function Overview
The flexible load strategy is concerned with the future use of controllable load to manage voltage variations in the low-voltage **(LV)** network arising from high penetration of solar and other embedded generation, and to reduce peak demand.

Description of the Change
In response to increasing electricity prices and generous government incentives for small scale renewables, more and more residential, commercial and industrial customers have been investing in onsite (embedded) generation. Whilst to some extent mitigating the impact of system peak demand growth, this dramatic uptake of renewable generation has significantly increased the range of power flows that the network must be able to support and the volatility of those power flows, particularly in the low voltage network. The network must now be able to support both the peak demands seen on the network in the evening on hot summer days as well as the negative flows experienced at solar noon on mild days when solar PV systems are providing peak output. Significant demand transients can also occur in such networks as clouds cross the sun and reduce solar output.

In combination, these effects can make it impossible for voltage levels within the LV network to be maintained within prescribed standards without upgrades of conductors or transformers, or more complex control algorithms and equipment. One of the greatest opportunities to manage this issue in the 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. Such loads may be utilised not only to reduce network peaks, thereby avoiding or deferring investment in network upgrades, but also to fill ‘troughs’ in demand, thereby enabling greater renewable integration within the network without the need to undertake costly remediation work to manage voltage compliance issues.

In the 2015-20 period we are proposing a number of activities targeted specifically to developing the capability in South Australia to use flexible loads to achieve greater network utilisation and to enable higher penetration of renewable generation in future, namely:

Customer education and cost reflective tariffs
Promoting the take-up of cost reflective tariffs at the point of sale of large appliances and providing customers with information on how to efficiently utilise the network.

Promote take-up of product

Promoting the take-up of customer side energy technologies that have the potential to improve the utilisation and operation of the network, including lobbying to remove the ban on large element electric hot water systems.

Promote AS475520 adoption

Supporting the mandating of AS4755 for electric vehicles, battery storage and air conditioning to support greater take-up of energy management systems and more cost-effective application of locational direct load control.

Reprogramming time switches

Reconfiguration of our management of controlled electric hot water to deal with today and tomorrow's network issues.

Direct Load Control foundations

Initiatives to reduce the costs of direct load control as a non-network solution.

What our stakeholders and customers have said to us

Our Customer Engagement Program confirmed that:

- a high level of customer support (89%) for upgrading and reinforcing the network where factors such as changing local demand, environment (ie corrosion) and the type of supply to an area (single line of supply);
- stakeholders and customers believe it is important to prioritise preventative maintenance to reduce network risks;
- customers are consuming less energy in response to rising electricity retail prices and they are investing in local solar PV generation, accelerated by generous government incentives;
- customers are changing the way they use the network with their continued uptake of DER (such as solar PV and other embedded generation) and this will require us to adapt the network accordingly;
- customers were initially unaware that the network had to be upgraded to enable DER 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 distributed energy resources.
- 88% of customers surveyed were satisfied with their current level of network reliability and have advised that they want current levels of reliability maintained; and
- inspecting, maintaining and upgrading the network was ranked in the top 3 community safety and reliability initiatives by customers in both the workshops and online survey.

Timing of the Change

From commencement of 2015 it is planned to employ a full time resource to administer a new database to track installation of AS4755-compliant devices and to commence an advertising campaign to promote the take-up of products that have features that enable load to be controlled dynamically.

Costing Methodology/Build Up

There are two new opex cost components arising from the flexible load strategy:

- 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.

[20] AS4755-2007 standard (Framework for demand response capabilities and supporting technologies for electrical products)

- 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. Advertising costs have been estimated at market rates.

No double counting of opex (eg output/scale)
Activities are targeted specifically to develop the capability to use flexible loads to achieve greater network utilisation and to enable higher penetration of renewable generation in future are planned for the 2015-20 RCP. Costs are incremental to the current RCP and are additional to normal output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	N/A
Materials	N/A	N/A	N/A	N/A	N/A	N/A
Services	N/A	N/A	N/A	N/A	N/A	N/A
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.101	0.101	0.101	0.101	0.101	**0.505**
Materials	-	-	-	-	-	**-**
Services	0.103	0.103	0.103	0.103	0.103	**0.515**
Total	**0.204**	**0.204**	**0.204**	**0.204**	**0.204**	**1.020**

Options Analysis

Our strategy in the 2015-20 RCP is one of modest, prudent expenditure in the short term in order to establish the foundations in South Australia that will create long-term opportunities to improve network efficiency through the use of flexible loads. For example:

- In the absence of an AS4755 interface the installation cost of a load control device could be as much as $125, often needing to be installed by a certified technician in order to retain the warranty of the appliance. The actual load control device can easily be double the cost it needs to be (as much as $50 extra per device) to accommodate the additional components and configurations required to be able to be retrofitted to a number of different appliance makes and models. Having an AS4755 interface would reduce the device cost and remove the need for certified skilled labour during the installation process, reducing the cost of direct load control of, for instance, air conditioning in constrained areas by around $100 per kVA[21].

- Although very little take up of electric vehicles and energy storage systems is predicted over the next 5 years (in part owing to the lack of products and incentives for those available in SA market), with the introduction of capacity based tariffs for small business and residential customers it is forecast up to 300,000 small storage units will be sold in SA over the next 20 years[22]. As a critical mass builds up, appropriate standards will enable us to offer additional incentives to some customers in exchange for some level of control of their unit to manage local voltage issues or improve network utilisation.

Alignment with the NER expenditure objectives and criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Whilst peak demand is not forecast to grow in the 2015-20 RCP, in that RCP we will begin to establish the market for new products such as battery storage that have the potential to have a significant impact on future demand. The approach is intended to ensure that future significant loads can be integrated with the network in a way that increases, rather than decreases, overall network efficiency and the delivery of standard control services.
Comply with all applicable regulatory obligations or requirements	We have a regulated requirement to maintain power quality at the customer supply point to Australian standards. There is significant potential in future to use flexible loads such as hot water or battery storage as a tool to manage power quality in areas of high solar penetration at lower cost than supply-side solutions such as re-conductoring, if the appropriate standards and processes are put in place.
Maintain safety of the distribution system	Prudent and efficient strategies for managing load flexibly supports our ability to maintain the safety of the distribution system

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	As take up of new products such as battery storage and electric vehicles increases, having appropriate standards in place will enable SA Power Networks to offer additional incentives to customers in exchange for some level of control of units to manage local voltage issues or improve network utilisation. This is a more efficient option than having to augment the SA Power Networks network to deal with this issue.

[21] See Appendix B for case studies
[22] Energeia forecast 2014

Operating Expenditure Criteria	Considerations
Cost that a prudent operator would require to achieve the objectives	We consider that this approach is the minimum reasonably required by a prudent operator to meet the needs of customers in the 2015-20 RCP and beyond. Taking into account the information we have today we consider that it would be *imprudent* to: fail to respond to rising network prices and decreasing network utilisation caused by inappropriate price signals in our current tariffs; fail to act to mitigate the predicted emergence of widespread power quality issues as solar PV penetration exceeds the limits of current infrastructure on feeders across all older areas of the LV network; continue to install obsolete and non-upgradable accumulation meters that cannot support new tariffs or provide the data that customers need to understand and manage their energy use.
Realistic expectation of demand and cost inputs required to achieve the objectives	Our supporting documentation demonstrates that our proposed expenditure meets this criterion.

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 – SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Attachment 20.34 – SA Power Networks: Flexible load strategy

3. Customer driven initiatives and changing community expectations

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 of our Proposal our comprehensive TalkingPower Customer Engagement Program (**CEP**) has specifically identified vegetation management, customer service and community safety as key focus areas of customers.

Table 9 summarises the forecast operating expenditure on 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 subsequent sections provide details of the individual step changes.

Table 9 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**

3.1. Vegetation management

3.1.1 Change in NBFRA trimming cycle

Reference	
Opex Chapter Reference	21.6.3
Expenditure Category(s)	DA-14 Vegetation Management
Regulatory Driver(s)	Change in Community Expectation (informed by Customer Engagement Program and Willingness to Pay research)
Forecast: 2015-2020 (June 15 $)	$13.5m

Category Function Overview
The principles of vegetation clearance are set out in the *Electricity Act 1996* (SA) and the *Electricity* (*Principles of Vegetation Clearance) Regulations 1996*. These principles establish a mandatory and prescriptive program for vegetation clearance in both bushfire and non-bushfire risk areas.

SA Power Networks is required to inspect and clear vegetation from around powerlines at regular intervals which cannot exceed 3 years. The key drivers for managing trees near powerlines are bushfire risk mitigation, maintaining reliability of electricity supply and ensuring public safety.

The current vegetation clearance program involves an annual inspection and clearance cycle in the bushfire risk areas and a not more than 3 year cycle in non-bushfire risk areas.

Description of the Change
There has been ongoing concern from Councils and communities, particularly in the metropolitan area, in relation to the current trimming practices and outcomes based on the 3 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.

Vegetation management around powerlines has been an ongoing concern for Councils and communities across South Australia. While the importance of tree pruning around powerlines is acknowledged, the visual outcome and structural stability of trees following pruning has raised concern amongst Councils and the community.

The quality and visual outcome of tree pruning has consistently been raised as an issue of major concern by Local Government and the community, particularly in the metropolitan area and within rural townships. SA Power Networks has undertaken extensive consultation over the past 12-18 months to understand customer values and expectations.

Engagement with Local Government and the community has indicated that a change to the trimming frequency would reduce the negative impact to the trees as a less severe cut would be required. As such, there is support from Councils for a shift to a 2 year cycle to improve the visual outcome of tree pruning to meet compliance.

Local Government engagement through the Local Government Forums has also highlighted the desire to achieve more aesthetically pleasing outcomes within communities and shift to a shorter clearance frequency. The key reasons include:

- improved visual amenity;
- increased frequency lessens amount of growth to trim; and
- less customer complaints.

During the Stage 1 TalkingPower workshops, one participant stated the following:
"We live in a tree lined street and therefore would want the most aesthetically pleasing outcome as possible" – Resident, metro.

Furthermore, targeted research with customers has shown a willingness to pay for a shift to a 2 year trimming cycle.

The Local Government Association (**LGA**) submission to SA Power Networks' Customer Engagement Program provided in-principle support for a two (2) year trimming cycle based on species identification and location. This increased frequency will allow for less severe cuts and improve the aesthetics and overall health of the tree. The submission noted that the current pruning techniques employed by SA Power Networks and their contractors combined with the frequency of pruning have been one of the most contentious issues for Local Government in South Australia.

What our stakeholders and customers have said to us
Our Customer Engagement Program confirmed that:

- 79% support better vegetation management approaches to improve the visual appearance of trees near power lines, and over time, reduce the need for trimming; and
- 65% of customers surveyed were willing to pay for a program of 2.5% tree removal and replacement program combined with a shift to a two year trimming cycle in NBFRAs.

Timing of the Change
In 2014/15, SA Power Networks commenced a 2 year cycle in the prescribed area (metropolitan Adelaide).

Costing Methodology/Build Up
The NBFRA program is currently undertaken on a 3 year cycle with approximately 40,000 units cut per annum at a cost, incorporating scoping and cutting, of $5.2 million. The preferred option of shifting to a 2 year cycle therefore results an incremental cost of $2.6 million per annum ($2.7 million when adjusted to June 15 $) relating to the additional 20,000 units cut.

No double counting of opex (eg output/scale)
This is a new initiative and these costs are incremental to the vegetation clearance costs that are reflected in our base year costs. Consequently, there is no duplication of costs associated with this in regard to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	-	**-**
Materials	N/A	N/A	N/A	N/A	-	**-**
Services	N/A	N/A	N/A	N/A	2.690	**2.690**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**2.690**	**2.690**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services	2.690	2.690	2.690	2.690	2.690	**13.450**
Total	**2.690**	**2.690**	**2.690**	**2.690**	**2.690**	**13.450**

Options Analysis

Option 1 - Business as Usual (Do Nothing)
SA Power Networks' experience is that the current 3 year vegetation clearance cycle in the metropolitan area requires trees to be cut to such an extent that the visual amenity is severely impacted, the health of the trees can be significantly affected and cutting can result in rapid regrowth of some species.

A shift to a 2 year cycle within the metropolitan area and rural townships is required to balance compliance requirements with Council and community expectations. The shift from a 3 year to a 2 year cycle in non-bushfire risk areas has strong support from the community to improve the visual outcome from tree pruning. This is a matter of widespread and consistent concern to the South Australian community.

Option 2 - Preferred Option
The preferred option is a shift from a 3 year to a 2 year cycle in metropolitan areas and rural townships. This will enable SA Power Networks to balance its legislative requirements with community expectations.

There is strong community support for a shift from a 3 year to a 2 year cycle in non-bushfire risk areas to improve the visual outcome from tree pruning. In addition, engagement with Local Government over the past 12 months has shown a strong support for a 2 year cycle.

Option 3 - Variable cycle cut

GHD proposed a step change for the 2015-2020 RCP to increase the frequency of cutting in the metropolitan council areas in particular, with the intention that less cutting (by volume) albeit more often will reduce the visual impact.

The GHD proposal included an estimate on the total number of units to be cut in the non-bushfire risk areas and metropolitan areas to ensure compliance (refer to GHD Justification of Costs Report Table 15 and 16, page 38). Based on these estimates, the total cost of this option was estimated at $16.1m.

This option was not supported by SA Power Networks due to the costs of the program and Council and community support was for a shift to a 2 year program.

Alignment with NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Prudent and efficient vegetation clearance practices will support our ability to meet and manage demand for SCS.
Comply with all applicable regulatory obligations or requirements	SA Power Networks is required by the *Electricity Act 1996* (SA) to take reasonable steps to clear vegetation around power lines in accordance with the principles of vegetation clearance set out in the *Electricity (Principles of Vegetation Clearance) Regulations 1996*. The inspection and clearance cycle cannot exceed 3 years. Within this outer limit of 3 years the actual length of the inspection and clearance cycle is firstly driven by the minimum clearance distances and secondly by what amounts to reasonable steps. In determining what amounts to reasonable steps, SA Power Networks must have regard to the concerns of customers identified during our Customer Engagement Program. Minimising visual impact whilst complying with the mandatory requirements was supported. Based on these concerns, and Willingness to Pay research, SA Power Networks is of the view that a shift to a 2 year cycle to improve the visual outcome of tree pruning whilst complying with the mandatory requirements is efficient and prudent and is a reasonable step.
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	A key driver for managing trees near power lines is maintaining the reliability of electricity supply.
Maintain safety of the distribution system	A key driver for managing trees near power lines is to ensure public safety.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach of shifting to a 2 year cycle is an efficient way of improving the visual outcome of tree pruning whilst complying with the mandatory vegetation clearance requirements and addressing the concerns of customers identified during our Customer Engagement Program, as compared to other options, such the GHD Option.
Cost that a prudent operator would require to achieve the objectives	It is prudent to consider and address in an efficient manner the concerns of customers identified during our Customer Engagement Program in relation to improving the visual outcome from tree pruning.
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the related objective. Cost inputs have been determined in accordance with the process outlined in Chapter 21 of the Proposal.

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.8 – The NTF Group: SAPN Targeted Willingness to Pay Research - research findings
- Attachment 6.9 – SA Power Networks: Discussion Paper - Directions for Vegetation Management, SA Power Networks long-term plan for managing trees near powerlines March 2014 - Refer to Section 4.2 *More frequent tree trimming* (page 15)
- Attachment 6.10 – SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Attachment 16.6 – SA Power Networks: TalkingPower Customer Engagement Program Summary
- Supporting Document 15.1 – Local Government Association of South Australia: Submission – Directions for Vegetation Management, June 2014
- Supporting Document 21.16 – GHD: Vegetation Strategy Reset submission justification of costs - Refer to Section 10 *Baseline Programs (page 32)*

3.1.2 Tree Removal and Replacement – BFRA

Reference	
Proposal Section	21.6.3
SEM Category(s)	DA-14 Vegetation Management
Regulatory Driver(s)	Change in Community Expectation (informed by Customer Engagement Program and Willingness to Pay research)
Forecast: 2015-2020 (June 15 $)	$9.2m (net)

Category Function Overview
The principles of vegetation clearance are set out in the *Electricity Act 1996* (SA) and the *Electricity* (*Principles of Vegetation Clearance) Regulations 1996*. These principles establish a mandatory and prescriptive program for vegetation clearance in both bushfire and non-bushfire risk areas.

SA Power Networks is required to inspect and clear vegetation from around power lines at regular intervals which cannot exceed 3 years. The key drivers for managing trees near power lines are bushfire risk mitigation, maintenance of reliability of electricity supply and ensuring public safety.

The current vegetation clearance program involves an annual inspection and clearance cycle in the bushfire risk areas (**BFRA**) and a not more than 3 year cycle in non-bushfire risk areas (**NBFRA**).

Description of the Change
A tree removal program is a common alternative to cutting practices employed by DNSPs to achieve clearance near power lines and reduce ongoing clearance requirements. A number of Councils have expressed interest in developing partnerships with SA Power Networks for the removal of inappropriate trees. In this way the volume of tree cutting going forward can be limited. Two trials have been implemented in partnership with Councils and further trials with interested Councils are currently being investigated.

Over the last 5 to 10 years there has been growing concern regarding tree trimming practices and the clearance levels required to meet our regulatory obligations. SA Power Networks has undertaken extensive consultation over the past 12-18 months to understand customer values and expectations. This consultation process has highlighted support for the removal of inappropriate trees as an alternative to ongoing vegetation clearance. The TalkingPower workshops identified a greater level of community acceptance for the removal of trees in bushfire areas being an effective means to mitigate the associated safety and bushfire risks.

The program will involve the removal of inappropriate, fast growing or large trees in consultation with Local Government and the community. The development of a replacement program, where appropriate, will provide ongoing environmental benefits. Trees being considered for removal will be assessed against a range of community, legislative and environmental factors, and be subject to a financial cost benefit analysis.

The tree removal program also extends to saplings as a preventative program aimed at reducing cutting requirements over time. The cost of sapling removal is significantly less than the cost of removing a mature tree, so a program targeting the removal of saplings within the vegetation clearance easement before they mature is a prudent approach. Removing saplings is also better from a visual perspective.

The Local Government Association (**LGA**) submission, on the 'SA Power Networks Directions for Vegetation Management Discussion Paper' recognised that whilst Councils do not support the wholesale removal of trees, a strategic tree replacement program may be appropriate to help curtail ongoing tree maintenance costs associated with inappropriate tree species or location. The development of guidelines to provide parameters for what is defined as an 'inappropriate tree' and parameters for a removal program, including sapling removal, must be undertaken in partnership with Local Government.

What our stakeholders and customers have said to us
Our Customer Engagement Program confirmed that:

- 79% support better vegetation management approaches to improve the visual appearance of trees near power lines, and over time, reduce the need for trimming;
- 73% supported the removal of trees and/or replacement with more appropriate vegetation; and
- 63% of customers surveyed were willing to pay for a program of 2.5% removal and replacement program combined with 135km of undergrounding in BFRAs.

Timing of the Change
A number of trials have been undertaken during 2014 with local government and further trials will be undertaken in early 2015.

In June 2014, a trial was undertaken in Echunga in partnership with the District Council of Mount Barker, and the Adelaide and Mt Lofty Ranges Natural Resources Management Board. The trial involved the clearance of 28 spans of woody weeds (*Fraxinus* and *Prunus*) and local eucalypts (*Eucalyptus camaldulensis*).

The key benefits for the three parties were the elimination of repetitive cutting, short and long term cost savings, improved amenity, reduced roadside fuel load, removal of spreading weed trees and residents being able to maintain verges with more ease.

Costing Methodology/Build Up
The preferred BFRA tree removal and replacement program option, detailed below, is based on Willingness To Pay support of 2.5% of infringing spans being cleared of problem trees. The volume of spans to be cleared is based on a starting position of 64,000 BFRA infringements. Therefore, the total spans to be 'cleared' in the first year is 1,600 spans and then reducing over time for example year 2 assumes 1,560 spans cleared (i.e 64,000-1,600*2.5%). The tree removal cost per span can vary greatly depending upon the volume of trees; tree type; location/accessibility for example. Based on external service provider advice which indicated a range of $50 to $50,000 and an initial trial, we have assumed a tree removal cost of $2,000 per span. In addition, provision has been made for a tree replacement cost of $150 per span.

The costs are then offset by the subsequent annual savings (i.e spans cleared) associated with the reduced cutting and associated traffic control; plus a significant portion of scoping costs. This equates to an annual saving of approximately $300 per span.

A further reduction in vegetation management costs of $1.3m has been included associated with the undergrounding of 135 km of line in BFRA over the 2015-20 RCP.

No double counting of opex (eg output/scale)
This is a new initiative and costs have not been incurred in our base year costs. Consequently, there is no duplication of costs associated with this in regard to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	-	**-**
Materials	N/A	N/A	N/A	N/A	-	**-**
Services	N/A	N/A	N/A	N/A	0.044	**0.044**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**0.044**	**0.044**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services (Net)	2.986	2.415	1.846	1.277	0.706	**9.230**
Total	**2.986**	**2.415**	**1.846**	**1.277**	**0.706**	**9.230**

Options Analysis

Option 1 – Business as Usual (Do Nothing)
If a tree removal and replacement program, including sapling removal, is not implemented ongoing vegetation clearance costs and requirements will continue to increase. The removal of trees within spans that require cutting every year will have an impact on the find rates and reduce ongoing vegetation clearance costs.

There are a number of Councils, particularly Councils in areas with high average rainfall and fast growing species, where it may be necessary to cut trees multiple times in a year to meet legislative requirements. In these situations tree removal is the most appropriate solution over the long-term as regular and ongoing clearance is required for compliance.

A tree removal and replacement program is a long term investment with a payback period of between approximately 7- 8 years with most of the benefit accruing in rural areas.

In our trials, consultation was undertaken on-site with a number of landowners prior to the trees being removed. Following the completion of the trial, the spokesperson for Scottsburn Rd sent an email stating:

"Whilst it always sad to remove any majestic trees, we, the residents of Scottsburn Rd feel that the removal of the trees was the eventual best outcome.
We do not support the wholesale removal of trees for convenience sake but these removed trees were suffering under intense pruning for years and at least now the problem and conflict has been taken care of."

Option 2 - Preferred option
Whilst Willingness to Pay research has shown strong community support for a vegetation removal and replacement for up to 10% in the bushfire risk areas, the preferred option is the implementation of a 2.5% tree removal and replacement program.
The key reasons are:

- A significant volume of spans require clearance associated with the implementation of up to a 10% removal program.
- The ability to deliver on the removal and replacement of up to 10% of spans in the BFRA.
- Initial costs associated with implementing a program of that scale.
- Community engagement process and consultation process required to remove and replace trees. South Australia has no provisions for tree removal within its legislation and as a result, it needs to rely on developing partnerships with Councils and private landowners to gain agreement to remove trees. A 10% program is likely to be impractical at this time.
- The 2.5% removal program consistently attracted the highest level of community acceptance and is manageable.
- Communities do not support wholesale removal of trees but support the removal of trees in certain circumstances to improve visual outcomes and community safety.

The total step change for the 2015-20 RCP comprises a gross removal and replacement cost of $17.8 million, offset by savings of $7.3 million and $1.3 million associated with the undergrounding of 135 km of line.

Alignment with NER expenditure objectives & criteria
Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Prudent and efficient vegetation clearance practices will support our ability to meet and manage demand for SCS.

Operating Expenditure Objectives	Considerations
Comply with all applicable regulatory obligations or requirements	SA Power Networks is required by the *Electricity Act 1996* (SA) and *Electricity (Principles of Vegetation Clearance) Regulations 1996* to inspect and clear vegetation from around power lines at intervals not exceeding 3 years. Within this outer limit of 3 years the actual length of the inspection and clearance cycle is firstly driven by the minimum clearance distances and secondly by what amounts to reasonable steps. In determining what amounts to reasonable steps, SA Power Networks must have regard to the concerns of customers identified during our Customer Engagement Program. The current vegetation clearance program involves an annual inspection and clearance cycle in BFRA. However, the removal of inappropriate, fast growing or large trees will reduce cutting requirements over time.
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	A key driver for managing trees near power lines is maintaining the reliability of electricity supply.
Maintain safety of the distribution system	A key driver for managing trees near power lines is to ensure public safety and mitigate bushfire risks.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach of implementing a tree removal program to meet compliance with the support of local councils will assist SA Power Networks in reducing costs associated with cutting requirements over time. Our preferred option represents the most efficient compromise.
Cost that a prudent operator would require to achieve the objectives	We consider that it is prudent to implement a program targeting the removal of inappropriate trees and saplings within vegetation clearance easements before they mature, to reduce cutting requirements over time.
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the related objective. Cost inputs have been determined in accordance with the process outlined in Chapter 21 of the Proposal.

In addition the AER decision on SA Power Networks' vegetation clearance pass-through in July 2013 made the following statement in relation to growth rates:

"Over an extended period of time, there are actions that a DNSP may pursue to reduce the overall growth rate and find rates affecting its network. These include tree replacement programs and information programs for councils and customers, to replace unsuitable trees with lower and slower growing species and encourage appropriate planting in future." (pg 23)

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 - SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Attachment 6.8 - The NTF Group: SAPN Targeted Willingness to Pay Research - research findings
- Attachment 6.9 - SA Power Networks: Discussion Paper - Directions for Vegetation Management, SA Power Networks long-term plan for managing trees near powerlines March 2014 - Refer to Section 4.1 *Tree Removal and Replacement Program* (page 12)
- Attachment 16.6 – SA Power Networks: TalkingPower Customer Engagement Program Summary
- Supporting Document 15.1 – Local Government Association of South Australia: Submission – Directions for Vegetation Management, June 2014
- Supporting Document 21.16 – GHD: Vegetation Strategy Reset submission justification of costs - Refer to Section 11 *Initiatives* (pg 38)
- Supporting Document 21.26 – SA Power Networks: Tree Removal Case Studies (Echunga and Riverton)

3.1.3 Tree Removal and Replacement – NBFRA

Reference	
Proposal Section	21.6.3
SEM Category(s)	DA-14 Vegetation Management
Regulatory Driver(s)	Change in Community Expectation (informed by Customer Engagement Program and Willingness to Pay research)
Forecast: 2015-2020 (June 15 $)	$6.1m (net)

Category Function Overview

The principles of vegetation clearance are set out in the *Electricity Act 1996* (SA) and the *Electricity (Principles of Vegetation Clearance) Regulations 1996*. These principles establish a mandatory and prescriptive program for vegetation clearance in both bushfire and non-bushfire risk areas.

SA Power Networks is required to inspect and clear vegetation from around powerlines at regular intervals which cannot exceed 3 years. The key drivers for managing trees near powerlines are bushfire risk mitigation, maintenance of reliability of electricity supply and ensuring public safety.

The current vegetation clearance program involves an annual inspection and clearance cycle in the bushfire risk areas and a not more than 3 year cycle in non-bushfire risk areas.

Description of the Change

The implementation of a tree removal and replacement program in the metropolitan area and rural townships will involve the removal of inappropriate, fast growing or large trees in consultation with Local Government and the community.

The program will also target problem trees from a safety and visual aesthetic perspective as there is growing support from Councils and the community that this approach in many instances is preferable to excessive and ongoing cutting. The development of a replacement program, where appropriate, will provide ongoing environmental benefits.

Trees being considered for removal will be assessed against a range of community, legislative and environmental factors, and be subject to a financial cost benefit analysis.

The Local Government Association (**LGA**) submission on the 'SA Power Networks Directions for Vegetation Management Discussion Paper' recognised that whilst Councils do not support the wholesale removal of trees, a strategic tree replacement program may be appropriate to help curtail ongoing tree maintenance costs associated with inappropriate tree species or location. The development of any guidelines to provide parameters for what is defined as an 'inappropriate tree' and parameters for a removal program, including sapling removal, must be undertaken in partnership with Local Government.

What our stakeholders and customers have said to us

Our Customer Engagement Program confirmed that:

- 79% support better vegetation management approaches to improve the visual appearance of trees near power lines, and over time, reduce the need for trimming;

- 73% supported the removal of trees and/or replacement with more appropriate vegetation; and
- 65% of customers surveyed were willing to pay for a program of 2.5% removal and replacement program combined with a shift to a two year trimming cycle in NBFRAs.

Timing of the Change

A number of trials have been undertaken during 2014 with Local Government and further trials will be undertaken during 2015.

A trial was undertaken in Riverton during 2014 in partnership with the Clare and Gilbert Valleys Council. The trial involved the removal of 8 Ash trees and 6 Pine trees at the entrance to Riverton and the replacement with a suitable slow growing and low/no maintenance species. The key benefits were improved visual outcome for the community, removal of unsightly trees and long-term cost savings. Council initially requested the removal of the 'unwanted and unsuitable trees' and approval and support from the Riverton Management Group was provided prior to the removals being undertaken. Council removed the stumps and replaced the trees with a more appropriate species for the location.

Costing Methodology/Build Up

The preferred NBFRA tree removal and replacement program option, detailed below, is based on Willingness To Pay support of 2.5% of infringing spans being cleared of problem trees. The volume of trees to be cleared is based on a two year cycle, which equates to approximately 60,000 trees per annum. Therefore, the total number of trees to be 'cleared' in the first year is 1,500 trees and then reducing over time for example year 2 assumes 1,462 trees cleared (i.e 60,000-1,500*2.5%).

The tree removal cost can vary greatly depending upon the volume of trees; tree type; location/accessibility for example. Based on external service provider advice and an initial trial, we have assumed a tree removal cost of $1,000 per tree (plus some allowance for significant trees). In addition, provision has been made for a tree replacement cost of $100 per tree (plus some allowance for significant trees).

The costs are then offset by the subsequent annual savings associated with the reduced cutting and associated traffic control; plus a significant portion of scoping costs. This equates to an annual saving of approximately $125 per tree.

No double counting of opex (eg output/scale)

This is a new initiative and costs have not been incurred in our base year costs. Consequently, there is no duplication of costs associated with this in regard to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	-	**-**
Materials	N/A	N/A	N/A	N/A	-	**-**
Services	N/A	N/A	N/A	N/A	0.024	**0.024**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**0.024**	**0.024**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services (net)	1.669	1.429	1.213	0.998	0.781	**6.090**
Total	**1.669**	**1.429**	**1.213**	**0.998**	**0.781**	**6.090**

Options Analysis

Option 1 – Business as Usual (Do Nothing)
If a tree removal program is not implemented, ongoing vegetation clearance costs and requirements will continue to increase. The removal of inappropriate or large trees in consultation with Local Government and the community is a change to the current cutting practices to achieve clearance near powerlines and reduce ongoing escalation in operational costs.

The LGA submission on the 'SA Power Networks Directions for Vegetation Management Discussion Paper' recognised that whilst Councils do not support the wholesale removal of trees, a strategic tree replacement program may be appropriate to help curtail ongoing tree maintenance costs associated with inappropriate trees species or position.

A tree removal and replacement program is a long term investment that can have a payback period in the range of 7-15 years as an average.

Option 2 - Preferred Option
Whilst the Willingness to Pay research showed strong community support for vegetation removal and replacement for up to 5% in the non-bushfire risk areas, the preferred option is the implementation of a 2.5% tree removal and replacement program. The key reasons are:

- A significant volume of spans require clearance associated with the implementation of an up to 5% removal program.
- The ability to deliver on the removal and replacement of up to 5% of trees in the non-bushfire risk areas.
- Initial costs associated with implementing a program of that scale.
- Community engagement and consultation process required to remove and replace trees, particularly in the non-bushfire risk areas where a high value is placed on street trees and visual amenity.
- The 2.5% removal program consistently attracted the highest level of community acceptance.
- Communities do not support wholesale removal of trees but support the removal of trees in certain circumstances to improve visual outcomes.

The total step change for the 2015-20 RCP comprises a gross removal and replacement cost of $9.3 million, offset by savings of $3.2 million.

Alignment with NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand	Prudent and efficient vegetation clearance practices will support our ability to meet and manage demand for SCS.
Comply with all applicable regulatory obligations or requirements	SA Power Networks is required by the *Electricity Act 1996* (SA) and *Electricity (Principles of Vegetation Clearance) Regulations 1996* to inspect and clear vegetation from around power lines at regulator intervals not exceeding 3 years. Within this outer limit of 3 years the actual length of the inspection and clearance cycle is firstly driven by the minimum clearance distances and secondly by what amounts to reasonable steps. In determining what amounts to reasonable steps, SA Power Networks must have regard to the concerns of customers identified during our Customer Engagement Program. The current vegetation clearance program involves an inspection and clearance cycle in NBFRA of not more than 3 years. However, the removal of inappropriate, fast growing or large trees will reduce cutting requirements over time.
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	A key driver for managing trees near power lines is maintaining the reliability of electricity supply.
Maintain safety of the distribution system	A key driver for managing trees near power lines is to ensure public safety.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Financial cost benefit analysis will be undertaken following the identification of suitable sites for tree removal and a reduction in cutting requirements will lead to a reduction in costs over time.
Cost that a prudent operator would require to achieve the objectives	We consider that it is prudent to implement a program targeting the removal of inappropriate trees to reduce cutting requirements over time.
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the related objective. Cost inputs have been determined in accordance with the process outlined in Chapter 21 of the Proposal. The costs include contractor costs for tree removal and replacement and assume a reduction in costs over the RCP as trees are removed.

In addition the AER decision on SA Power Networks vegetation clearance pass-through in July 2013 made the following statement in relation to growth rates:

"Over an extended period of time, there are actions that a DNSP may pursue to reduce the overall growth rate and find rates affecting its network. These include tree replacement programs and information programs for councils and customers, to replace unsuitable trees with lower and slower growing species and encourage appropriate planting in future." (pg 23)

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.8 – The NTF Group: SAPN Targeted Willingness to Pay Research - research findings
- Attachment 6.9 – SA Power Networks: Discussion Paper - Directions for Vegetation Management, SA Power Networks long-term plan for managing trees near powerlines March 2014 - Refer to Section 4.1 *Tree Removal and Replacement Program* (page 12)
- Attachment 6.10 – SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Attachment 16.6 – SA Power Networks, TalkingPower Customer Engagement Program Summary
- Supporting Document 15.1 – Local Government Association of South Australia: Submission – Directions for Vegetation Management, June 2014
- Supporting Document 21.16 – GHD: Vegetation Strategy Reset submission justification of costs - Refer to Section 11 *Initiatives* (pg 38)
- Supporting Document 21.26 – SA Power Networks: Tree Removal Case Studies (Echunga and Riverton)

3.1.4 Advanced tree trimming practices

Reference	
Proposal Section	21.6.3
SEM Category(s)	DA-14 Vegetation Management
Regulatory Driver(s)	Change in Community Expectation (informed by Customer Engagement Program)
Forecast: 2015-2020 (June 15 $)	$1.9m

Category Function Overview
The principles of vegetation clearance are set out in the *Electricity Act 1996* (SA) and the *Electricity* (*Principles of Vegetation Clearance) Regulations 1996*. These principles establish a mandatory and prescriptive program for vegetation clearance in both bushfire and non-bushfire risk areas.

SA Power Networks is required to inspect and clear vegetation from around powerlines at regular intervals which cannot exceed 3 years. The key drivers for managing trees near powerlines are bushfire risk mitigation, maintenance of reliability of electricity supply and ensuring public safety.

The current vegetation clearance program involves an annual inspection and clearance cycle in the bushfire risk areas and a not more than 3 year cycle in non-bushfire risk areas.

Description of the Change
Over the last 5 to 10 years there has been growing concern regarding tree trimming practices and the clearances required to meet our legislative requirements. Managing vegetation under powerlines is complex, particularly in metropolitan areas where residents place a high value on street trees and visual amenity.

SA Power Networks has undertaken extensive consultation over the past 12 to 18 months to understand customer values and expectations. The quality and visual outcome of tree pruning has consistently been raised as an issue of major concern by Local Government and the community, particularly in the metropolitan area and within rural townships.

Local Government has highlighted through the Local Government Forums the desire to achieve more aesthetically pleasing outcomes within their communities. The TalkingPower workshops also highlighted that the community place a high value on visual amenity.

During the Stage 1 TalkingPower Customer Engagement Program workshops, one participant stated the following:
"We live in a tree lined street and therefore would want the most aesthetically pleasing outcome as possible" – Resident, metro.

There is a compelling need to consider alternative pruning techniques to improve the visual aesthetics, as well as the health, structure and growth rates of trees identified for clearance.
To address this issue we propose to engage a number of qualified arborists to provide expert advice and input into more advanced trimming practices. The arborists would work closely with Local Government on a number of trimming trials and techniques in selected areas.

The trials will aim to determine whether there will be a significant change in the growth pattern of the trees with the use of different trimming practices, versus trimming more regularly in order to maintain compliance.

What our stakeholders and customers have said to us

Our Customer Engagement Program confirmed that 79% support better vegetation management approaches to improve the visual appearance of trees near power lines, and over time, reduce the need for trimming.

Timing of the Change

Whilst we will commence the recruitment process during 2014/15 it is anticipated that the arborists will not start until mid 2015.

Costing Methodology/Build Up

SA Power Networks will engage a number of qualified arborists to provide expert advice and input into trimming practices, including a trial of more advanced trimming practices and working more collaboratively with Local Government.

The trial would look at the time and cost impact of using these tree trimming practices, consider their ability to maintain compliance with the Regulations and the long-term benefits of these practices in terms of tree health, amenity, stability, customer response, Regulatory compliance and at a price which customers are willing to bear.

The costing incorporates the labour cost including a vehicle for three arborists over the period. The trial would provide a better understanding of the cost and practicality of undertaking more advanced tree trimming practices and determine whether there would be a significant change in the growth pattern of the trees with the use of more advanced trimming practices, versus trimming more regularly in order to maintain compliance.

No double counting of opex (eg output/scale)

This is a new initiative and costs have not been incurred in our base year costs. Consequently, there is no duplication of costs associated with this in regard to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	**N/A**
Materials	N/A	N/A	N/A	N/A	N/A	**N/A**
Services	N/A	N/A	N/A	N/A	N/A	**N/A**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	0.372	0.372	0.372	0.372	0.372	**1.860**
Materials	-	-	-	-	-	**-**
Services	-	-	-	-	-	**-**
Total	**0.372**	**0.372**	**0.372**	**0.372**	**0.372**	**1.860**

Options Analysis

Option 1 Business as Usual (Do Nothing)

The pruning techniques employed by SA Power Networks and their contractors have been one of the most contentious issues for Local Government in South Australia over the past 5-10 years. The current trimming practices are based on meeting our legislative requirements. This is a matter of widespread and consistent concern to the South Australian community.

As noted by the LGA submission on the 'SA Power Networks Directions for Vegetation Management Discussion Paper', the engagement of arborists and a trial of more advanced tree trimming practices will enable SA Power Networks to work collaboratively with Local Government to understand the time and cost impact of using these tree trimming practices, how they can be used to meet our regulatory obligations and the long-term benefits.

The LGA also believes that additional resourcing will enable SA Power Networks to undertake better quality vegetation management.

If nothing is done, SA Power Networks will continue to undertake clearance to meet its legislative requirements and Councils and the community will continue to raise concerns regarding vegetation management around powerlines and the resulting aesthetic outcome.

SA Power Networks has been working closely with Local Government to understand its priorities and expectations over the last 12 months and a trial would provide opportunities to investigate and assess the benefits of undertaking more advanced trimming practices.

Option 2 - Preferred Option

The preferred option is to engage a number of qualified arborists to provide expert advice and input into trimming practices, including a trial of more advanced trimming practices. The trial will enable us to balance our legislative requirements with community expectations.

A trial would involve selecting a sample of trees across one or multiple metropolitan and regional councils to test alternative trimming practices. The trial would assess the value of applying more advanced tree trimming practices, taking into account good horticultural practices and species requirements.

Alignment with NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Prudent and efficient vegetation clearance practices will support our ability to meet and manage demand for SCS.
Comply with all applicable regulatory obligations or requirements	SA Power Networks' current trimming practices are based on meeting legislative requirements under the *Electricity Act 1996* (SA) and *Electricity (Principles of Vegetation Clearance) Regulations 1996*. However, these practices have been one of the most contentious issues for Local Government in South Australia over the past 5-10 years. Within this outer limit of 3 years the actual length of the inspection and clearance cycle is firstly driven by the minimum clearance distances and secondly by what amounts to reasonable steps. In determining what amounts to reasonable steps, SA Power Networks must have regard to the concerns of customers identified during our Customer Engagement Program. SA Power Networks is required to have regard to the concerns of customers which in this case involves working closely with Local Government to understand its priorities and expectations over the last 12 months and undertaking a trial to investigate and assess the benefits of undertaking more advanced trimming practices.
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	A key driver for managing trees near power lines is maintaining the reliability of electricity supply.
Maintain safety of the distribution system	A key driver for managing trees near power lines is to ensure public safety.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach involves assessing a sample of trees to determine the value of applying more advanced tree trimming practices, taking into account good horticultural practices and species requirements. Once this assessment has been completed, we will be in a position to determine how we can meet our legislative requirements and the concerns of customers at the lowest cost.
Cost that a prudent operator would require to achieve the objectives	We consider that a prudent operator would look at the time and cost impact of using its tree trimming practices, consider their ability to maintain compliance with the Regulations and the long-term benefits of these practices in terms of tree health, amenity, stability, customer response, regulatory compliance and at a price which customers are willing to bear.

Operating Expenditure Criteria	Considerations
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the related objective. Cost inputs have been determined in accordance with the process outlined in Chapter 21 of the Proposal.

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.8 - The NTF Group: SAPN Targeted Willingness to Pay Research - research findings
- Attachment 6.9 - SA Power Networks: Discussion Paper - Directions for Vegetation Management, SA Power Networks long-term plan for managing trees near powerlines March 2014 - refer to section 4.3 *Pruning techniques* (page 16)
- Attachment 6.10 – SA Power Networks: Directions and Priorities 2015 to 2020 consulation document
- Attachment 16.6 – SA Power Networks: TalkingPower Customer Engagement Program Summary
- Supporting Document 21.16 – GHD: Vegetation Strategy Reset submission justification of costs - Refer to Section 11 *Initiatives* (page 40)
- Supporting Document 15.1 – Local Government Association of South Australia: Submission – Directions for Vegetation Management, June 2014

3.1.5 Community engagement and consultation

Reference	
Proposal Section	21.6.3
SEM Category(s)	A-3 Communications
Regulatory Driver(s)	Change in Community Expectation (informed by Customer Engagement Program)
Forecast: 2015-2020 (June 15 $)	$1.2m

Category Function Overview
Enhanced community and stakeholder engagement, enabling the effective implementation of the long term vegetation management strategy.

Description of the Change
Throughout our lengthy and thorough Customer Engagement Program, customers indicated that they want to know more and be happier about vegetation management. This is a source of many complaints and comments, particularly from metropolitan Adelaide. Customers also cited that public safety is the main priority area that we should address in all areas of our management of network assets.

Community and stakeholder engagement is critical to the successful implementation of the long term vegetation management strategy. We are working with the LGA and Councils on the establishment of a long-term plan for vegetation management, including the development of a protocol for vegetation management near powerlines. The protocol will include agreement with Councils on how we work together to manage vegetation near powerlines, including pruning techniques and programs; alternatives to clearance; community consultation and management of historic and sensitive trees.

The protocol will outline the baseline of programs for vegetation management. If individual Councils require additional programs, Councils would be required to contribute funding for specific programs.

What our stakeholders and customers have said to us
Our Customer Engagement Program confirmed that:

- customers have new expectations about how and when we communicate with them and they want more information about the electricity industry;
- 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;
- customers want more choice in how they interact with us;
- customers increasingly value self-service technologies and access to information and services wherever they are;
- 61% of customers surveyed said we should be proactive and responsive, and continue to improve our interactions with them;

- customers support SA Power Networks upgrading the network to allow two-way flows and enable the increasing uptake of new technologies;
- customers support the phased introduction of socially equitable cost-reflective pricing strategies;
- customers clearly expressed a need for education on new technologies and changes to the industry;
- customers still value contact centre services; and
- raising community awareness through engagement, education and partnerships is essential.

Proposed Activity

The process outlined above will be complemented by a communications plan with targeted media campaigns for customers in council areas most affected by vegetation activities, as well as some specific advertising with an environmental or gardening theme, to better educate customer segments with a specific connection to vegetation. To efficiently facilitate initiatives such as tree removal programs a dedicated resource will directly liaise with land and property owners.

The additional activity includes:

- A targeted campaign for 10 affected areas per year. Proposed media includes:
    - Metropolitan press; and
    - Regional press – relating to the affected area only.

- A broader campaign over a four week period with an environmental/gardening focus to help raise awareness and support of the vegetation program. Proposed media includes:
    - Metropolitan/regional press;
    - Metropolitan radio – gardening focus; and
    - Digital – gardening and environmental focus.

- Throughout the year we will continue to liaise with LGAs, Local Councils and major interest groups (like Trees for Life) to implement the long-term plan for vegetation management.

The types of messages our communications will carry are:

- what can/can't be planted under/near powerlines;
- the rationale and details behind our tree trimming program;
- general safety messages about vegetation management; and
- how we're working with the LGA and Councils on the establishment of a long-term plan for vegetation management.

For more information on the proposed campaign including detailed costings, see the Communication Plan 2014-2020.

Costing Methodology/Build Up

Our media schedule has been worked out very carefully with our media buying agency and creative agency. Whilst suggesting more than we have done in the past, we are proposing a light/medium-weight touch to build strong levels of reach and frequency, ensuring that the broader community can be better informed about vegetation management. The weightings have all been modelled on a pragmatic level of spend, therefore applying a prudent and efficient approach.

Where possible we are taking maximum advantage of new digital technologies, which provide a cheaper alternative to the more traditional media channels. They can also be very targeted to digital media with an environmental and gardening focus, as can some radio advertising during gardening programs, for example.

The most economical way to communicate with communities directly affected by our vegetation management is through print, therefore advertising is proposed in metropolitan and regional press following the tree trimming schedule.

Similar levels of spend are proposed annually, to ensure affected communities receive sufficient communications and the broader community are continually educated about this important, and contentious topic.

All costings adopt current market rates.

No double counting of opex (eg output/scale)
This is a new initiative and costs have not been incurred in our base year costs. Consequently, there is no duplication of costs associated with this in regard to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	**N/A**
Materials	N/A	N/A	N/A	N/A	N/A	**N/A**
Services	N/A	N/A	N/A	N/A	N/A	**N/A**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services	0.256	0.233	0.239	0.233	0.238	**1.199**
Total	**0.256**	**0.233**	**0.239**	**0.233**	**0.238**	**1.199**

Options Analysis

Option 1 – Business as Usual (Do Nothing)
As indicated above, vegetation management is a matter of widespread and consistent concern among the South Australian community. Our comprehensive Customer Engagement Program confirms that our customers expect improved vegetation management performance on a number of fronts from SA Power Networks, as represented by sections 3.1.1 to 3.1.4 above. In the absence of appropriate communications and feedback of the type described, the community may remain unaware of the improved vegetation management performance, thereby reducing customer satisfaction.

Option 2 - Preferred Option
The preferred option is to undertake enhanced community and stakeholder engagement relating to the long term vegetation management strategy. The strategy will assist in dissemination of information regarding the long term vegetation management strategy and its performance, enhancing awareness, understanding and satisfaction.

The additional communication activities planned will result in the following:

- Fulfils customers' desire for more information on this contentious topic.
- Gives our customers more information and improves service levels, which is likely to increase satisfaction.
- Customers can play more of an active role in helping us manage vegetation.
- Manages the pressure on the call centre and potential backlash regarding tree-trimming.

We note that similar campaigns are also very prominent in the communication activities of other DNSPs such as ActewAGL, Aurora Energy, AusGrid, Endeavour Energy, Energex, Ergon Energy, Essential Energy, Horizon Power, Jemena, Power and Water Corporation, SP AusNet and Western Power.

We are taking advantage of having such specific target markets by only proposing a light advertising schedule over 4 weeks in the metropolitan/regional press that covers the affected area. The broader campaign is also very targeted aimed at metropolitan areas, where vegetation management is more contentious, and aimed at customers with an environmental/gardening focus via press and radio – thereby aimed at the customers who have the deepest interest in this subject.

Alignment with NER expenditure objectives & criteria
Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Prudent and efficient vegetation clearance practices that are clearly communicated to customers will support our ability to meet and manage demand for SCS.

Operating Expenditure Objectives	Considerations
Comply with all applicable regulatory obligations or requirements	SA Power Networks is required by the *Electricity Act 1996* (SA) and *Electricity (Principles of Vegetation Clearance) Regulations 1996* to inspect and clear vegetation from around power lines at regulator intervals not exceeding 3 years. The current vegetation clearance program involves an inspection and clearance cycle in NBFRA of not more than 3 years. However, by educating customers about what can and cannot be planted under or near power lines we can avoid having to remove inappropriate, fast growing or large trees and reduce cutting requirements over time.
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	A key driver for managing trees near power lines is maintaining the reliability of electricity supply. By educating customers about what can and cannot be planted under or near power lines we can reduce this risk and reduce the costs that we incur in vegetation management.
Maintain safety of the distribution system	A key driver for managing trees near power lines is to ensure public safety. By educating customers about what can and cannot be planted under or near power lines we can reduce this risk and reduce the costs that we incur in vegetation management.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	We are proposing a light/medium-weight touch to build strong levels of reach and frequency, ensuring that the broader community can be better informed about vegetation management. All planned advertising will be priced at market rates. The weightings have all been modelled on a pragmatic level of spend, therefore applying a prudent and efficient approach. Community and stakeholder engagement is also critical to the successful implementation of our long term vegetation management strategy.
Cost that a prudent operator would require to achieve the objectives	We consider that our approach is required for us to appropriately discharge these responsibilities and reflects what a prudent operator would do to meet the needs of customers in the 2015-20 RCP and beyond. Similar campaigns are very prominent in the communication activities of other DNSPs such as ActewAGL, Aurora Energy, AusGrid, Endeavour Energy, Energex, Ergon Energy, Essential Energy, Horizon Power, Jemena, Power and Water Corporation, SP AusNet and Western Power.
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the related objective. Cost inputs have been determined in accordance with the process outlined in Chapter 21 of the Proposal.

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 - SA Power Networks: Directions and Priorities 2015 to 2020 Consultation Document
- Supporting Document 21.16 – GHD: Vegetation Strategy Reset Submission Justification of Costs– Section 11
- Supporting Document 21.25 – SA Power Networks: Communications Plan

3.2. Customer service

3.2.1 Customer education and consultation

Reference	
Proposal Section	21.6.3
SEM Category(s)	A-3 Communications
Regulatory Driver(s)	Change in Community Expectation
Forecast: 2015-2020 (June 15 $)	$1.7m

Category Function Overview
Program to educate customers on the electricity industry so that they better understand who we are and what we do, and how they may benefit from the many changes underway in the industry and the way they use energy.

Description of the Change
Throughout our lengthy and thorough Customer Engagement Program, customers overwhelmingly indicated that they want more information about SA Power Networks; our role in the electricity industry; the role of retailers; and the electricity industry in South Australia. They also want more specific information about changes in the industry, such as tariffs and changing energy options, so they can make more informed choices. We don't need, or seek, to be the face of the electricity industry, but we certainly need to be more vocal about SA Power Networks, where we fit in and the important role we play in the immediate and long term interests of consumers. Customers have told us they are confused about these issues and are seeking clarity from us. Customers consider that we are positioned well in the supply chain to help them understand the industry and the available options to enable them to manage their electrical needs. They see us, or want to see us, as a trusted source of advice, and we are therefore proposing to respond to this clear need.

If customers better understand who we are and what we do, then we are more likely to become a more recognisable and trusted supplier and listen and act upon the important messages that we deliver. Without customer awareness, knowledge and trust, the challenge of communicating some of the more complex messages such as Demand Side Participation will be greater and much more difficult.

Consequently, this initiative responds to customers' calls for more and better information resources from SA Power Networks, and will help establish a platform for the more complex communication tasks to come.

What our stakeholders and customers have said to us
Our Customer Engagement Program confirmed that:

- customers have new expectations about how and when we communicate with them and they want more information about the electricity industry;
- 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;
- customers want more choice in how they interact with us;

- 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; and
- raising community awareness through engagement, education and partnerships is essential.

Proposed Activity

To date, the advertising we have undertaken has tended to be quite specific, and aimed at customers affected by vegetation management, bushfire safety, etc. We have proactively done little or no advertising and communication of a more general nature.

We are proposing a broad media campaign, lasting 3 months, every other year during the 2015-20 RCP. As the electricity industry, and our role within it, changes over time, we will need a platform to keep customers abreast of those changes.

Having largely implemented our extensive Customer Engagement Program, we now need a way of continuing this engagement on an ongoing basis, so we are developing our Stakeholder Engagement Strategy. This Strategy will provide an organisation-wide framework for engaging stakeholders for the 2015-20 RCP. It aims to build on recent customer consultation undertaken as part of the preparations for our Proposal and to inform our engagement approach when dealing with customers, industry, government, regulatory, business, media, regional and internal stakeholders. It will assist the business to manage key issues identified in the Strategic Plan 2014- 2018 and our Future Operating Model, and deliver the outcomes from our 2015-20 Determination. Communication materials like brochures, presentation materials, videos, DVDs and website will be needed to efficiently deliver the communication aspects of the Stakeholder Engagement Strategy.

Finally, we intend to take advantage of our 800-strong fleet of trucks and cars by each vehicle having appropriate signage to support our education and information initiatives.

The additional activity includes:

- A bi-annual 3-month media campaign taking place at an appropriate time of year (to fit with other campaigns) in 2016, 2018 and 2020. Proposed media includes:
    - Metropolitan TV;
    - Regional TV; and
    - Digital.

- Fleet signage to be replaced every two years. Signage will be added in 2016, and then replaced in 2018 and 2020, in order to (appropriately) keep the messages fresh and relevant.

- Refreshing and updating all our stakeholder engagement materials on an annual basis starting in 2016 (for which a small amount of additional cost has been included), including the production of a DVD in 2019.

The types of messages our communications will carry are:

- who is SA Power Networks?
- what do we do?
- some context of performance eg. network reliability, cost and service compared with other states;
- energy management options;

- clarity on the bill breakdown of charges;
- information on solar PV; and
- overview of other changes to the industry for example demand side participation (more specific details are covered in the DSP project) and distributed energy technologies including renewable energy, electric vehicles, onsite energy storage and trigeneration. This will carry through the Stakeholder Management materials, as well as provide details on the Future Operating Model.

More information on the proposed campaign including detailed costings, is provided in the Communication Plan 2014-2020.

Costing Methodology/Build Up

Our media schedule has been worked out very carefully with our media buying agency and creative agency. We are proposing a medium-weight touch to build strong levels of reach and frequency, ensuring that the broader community can receive important messages. The weightings have all been modelled on a pragmatic level of spend, therefore applying a prudent and efficient approach.

Due to the amount of confusion from customers we have selected high reach media channels in order to reach more people. According to the Roy Morgan advertising survey in 2013, commercial TV and the internet have the maximum amount of reach, so we have decided to exclusively focus on those channels, rather than spend even more money on print, radio and outdoor which typically have less reach.

We have taken a pragmatic approach of having no media activities on this subject every other year, so the advertising activity is only scheduled for 2016, 2018 and 2020 as we need to keep customers abreast of continuing changes to the industry.

The stakeholder engagement material cost is made up of graphic design, printing, video, DVD production, website and other digital assets to help us communicate effectively and implement the Stakeholder Engagement Strategy.

All costings adopt current market rates.

No double counting of opex (eg output/scale)

This is a new initiative and costs have not been incurred in our base year. Consequently, there is no duplication of costs associated with this in regard to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	**N/A**
Materials	N/A	N/A	N/A	N/A	N/A	**N/A**
Services	N/A	N/A	N/A	N/A	N/A	**N/A**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services	0.656	0.026	0.461	0.097	0.462	**1.702**
Total	**0.656**	**0.026**	**0.461**	**0.097**	**0.462**	**1.702**

Options Analysis

Option 1 – Business as Usual (Do Nothing)
Doing nothing is not viable in the current and forecast environment. There is currently an information and 'trust' deficit that will impede our ability to build critical support among customers for the complex changes ahead, in areas such as cost-reflective tariffs, demand side participation, and so on.

Option 2 - Preferred Option
The preferred option is to undertake enhanced customer education and consultation relating to a wide range of industry, sector, SA Power Networks and customer energy usage matters. This approach will increase customers' access to information they are demanding, help increase their trust in the sector and SA Power Networks, help improve their satisfaction and position us for more effective communication required for important changes to come (eg cost-reflective tariffs, demand side participation, etc).

The additional planned communication activities will result in the following:

- Reduces customer confusion and therefore time inefficiencies;
- Customers know who we are and what we do, so they can engage with us more effectively and efficiently;
- Gives our customers better information and improves service levels, which is likely to increase satisfaction;
- Gives customers more information on emerging and alternative energy technologies to make more informed, efficient and cost-effective choices;
- Creates a better foundation of trust, for the communication of future complex changes;
- Fleet signage creates a greater customer appreciation of our physical presence in the South Australian community;
- Using 800 'free' billboards (fleet) is a cost-effective way of communicating; and
- Ensures that the investment in initiatives like Smart Meters, Tariffs and the Stakeholder Management Strategy realises maximum benefits for customers and other stakeholders.

A three month advertising campaign ensures we cover a reasonable amount of time for maximum reach without over-communicating. By limiting the advertising activities to every other year this ensures we have a platform to communicate ongoing changes in the industry and remain relevant and effective without bombarding our customers with messages.

Using our fleet to carry inexpensive signage, changed every two years to keep the messaging fresh, is a very effective way of using our assets to work harder for us. At the moment our fleet merely carries the SA Power Networks logo. By improving and extending the signage we can add further important messages, at relatively low cost but with good geographic coverage across the State.

Alignment with NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	In order to continue to meet and manage the expected demand for standard control services in the changing operating environment outlined above, we need to better inform and educate customers about important changes in the industry, such as tariffs, changing energy options, etc, so they can make appropriately informed and efficient choices for their own benefit. For example, effective tariff reform is central to managing the expected demand for regulated services over the 2015-20 RCP and beyond. By phasing in cost-reflective network tariffs for customers at the point at which they are making investment decisions that will affect their demand on the network, we will encourage choices and behaviours that will increase utilisation of existing network assets, reducing the need for network augmentation in the longer term. Tariff changes are often a highly challenging topic for customers, so effective customer communication will be an essential part of ensuring a smooth implementation of these critical reforms.
Comply with all applicable regulatory obligations or requirements	We have a number of regulatory obligations in relation to the provision of standard control services, and having better informed and educated customers assists us in meeting those obligations.
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	Having better informed and educated customers assists us in maintaining quality, reliability and security of supply.
Maintain safety of the distribution system	Better informed and educated customers are more likely to understand and assist us in delivering safety benefits. For example, assisting us to transition to smarter metering can deliver a number of safety benefits, including the detection of degraded neutral at customer premises, detection of continued energy export from embedded generators during loss of grid supply due to inverter faults, and so on.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach is a cost-effective way of communicating important messages. All planned advertising will be priced at market rates. Weightings have been modelled on a pragmatic level of spend, therefore applying an efficient and prudent approach.
Cost that a prudent operator would require to achieve the objectives	As industry changes accelerate, effective information and communication to customers will be critical to effective program implementation, so our approach will assist us in appropriately discharging our responsibilities and reflects what a prudent operator would do to meet the needs of customers in the 2015-20 RCP and beyond. Similar actions are taken by other DNSPs (including Energex and AusGrid).
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the objectives.

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.6 - SA Power Networks: Customer Service Strategy 2014-2020
- Attachment 6.7 - Deloitte, SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 – SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Attachment 7.7 – SA Power Networks: Future Operating Model 2013-2028
- Supporting Document 21.25 – SA Power Networks: Communications Plan

3.2.2 Self Service Products

Reference	
Proposal Section	21.6.3
SEM Category(s)	A-3 Communications
Regulatory Driver(s)	Change in Community Expectation
Forecast: 2015-2020 (June 15 $)	$1.0m

Category Function Overview
Implementation of a tailored digital advertising strategy to support the launch, and communication, of new self service options.

Description of the Change
Throughout our lengthy and thorough Customer Engagement Program, customers said they want us to improve service interactions and they want to interact with us using multiple channels for a variety of different actions. Customers want more information and more responsive services. Our Customer Service Strategy will deliver new self-service options and products, and it will be essential to communicate availability of this new source of value to customers if benefits and efficiencies are to be optimised.

What our stakeholders and customers have said to us
Our Customer Engagement Program confirmed that:

- customers have new expectations about how and when we communicate with them and they want more information about the electricity industry;
- 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;
- customers want more choice in how they interact with us;
- customers increasingly value self-service technologies and access to information and services wherever they are;
- 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; and
- raising community awareness through engagement, education and partnerships is essential.

Proposed Activity
In support of the Customer Services Strategy of delivering customer service that is tailored and responsive to immediate and changing needs, we will implement some specific advertising designed to promote these new technologies that are cited in the Customer Service Technology Plan.

The additional activity includes:

- A three month media campaign in 2016 and 2017 with a particular focus on digital advertising, supported by some more traditional advertising. Advertising activity is planned to reduce by more than 50% in the remaining years of the RCP – although activity will ultimately be tied to when services become available (and therefore need promoting). Proposed media includes:

- Strong mobile device-based campaign;
- Metropolitan/regional press;
- Metropolitan/regional radio; and
- Digital video campaign.

The types of messages our communications will carry are:

- promotion of the self-service options eg. mobile services that include customer mobile applications;
- ease of use via mobile devices; and
- 24/7 access to information.

For more information on the proposed campaign including detailed costings, see the Communication Plan 2014-2020.

Costing Methodology/Build Up

Our media schedule has been worked out very carefully with our media buying agency and creative agency. We're proposing a medium-weight touch, mainly online, as this is the medium that will be used for the self-service technologies, therefore it makes sense to capitalise on the digital opportunities in relation to advertising too. The digital component will be supported by a limited amount of metropolitan/regional radio and press. The weightings have all been modelled on a pragmatic level of spend, therefore applying a prudent and efficient approach.

A slightly heavier advertising program is proposed in 2016 and 2017 to raise awareness levels more quickly, to ensure that the self-service technologies planned as part of the implementation of the Customer Services Strategy receive an adequate level of promotion and take-up. The campaigns will drop back in 2018 - 2020 with more than a 50% reduction, on the assumption that take-up will be needed most in the first two years. Ultimately though, the advertising activity will be tied to when services become available.

All costings adopt current market rates.

No double counting of opex (eg output/scale)

This is a new initiative and costs have not been incurred in our base year. Consequently, there is no duplication of costs associated with this in regard to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	**N/A**
Materials	N/A	N/A	N/A	N/A	N/A	**N/A**
Services	N/A	N/A	N/A	N/A	N/A	**N/A**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services	0.417	0.283	0.111	0.103	0.112	**1.026**
Total	**0.417**	**0.283**	**0.111**	**0.103**	**0.112**	**1.026**

Options Analysis

Option 1 – Business as Usual (Do Nothing)
Doing nothing is not recommended. Our Customer Engagement Program has clearly demonstrated a high demand for self-service options as detailed in our Customer Service Strategy, and omitting appropriate communication of the benefits available via these new options will reduce the extent to which those benefits, and the efficiencies that they will provide, are realised.

Option 2 - Preferred Option
The preferred option is to communicate the availability and functionality of new self-service options to customers to increase their utilisation in line with customer preferences, and thereby maximise the benefits and efficiencies realised.

The additional communication activities planned will result in the following:

- customers can engage with us better using new digital tools;
- helps customers to manage their energy needs and costs better and more efficiently;
- gives our customers more information and improves service levels, which is likely to increase satisfaction; and
- ensures the investment in the initiative realises the maximum benefits for the customer.

A three month advertising campaign in 2016 and 2017 will ensure that we get adequate take-up for the new technologies without over-communicating, and by ‘winding back’ the campaign in 2018 - 2020 we will ensure that more promotion of additional technologies and improvements can take place, as they become available.

Alignment with NER expenditure objectives & criteria
Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Providing customers with the information they need to utilise efficient self-service technologies and systems, supports our ability to meet and manage demand for standard control services.
Comply with all applicable regulatory obligations or requirements	We have a number of regulatory obligations in relation to the provision of standard control services, and having better informed and educated customers assists us in meeting those obligations.

Operating Expenditure Objectives	Considerations
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	Having better informed and educated customers assists us in maintaining quality, reliability and security of supply.
Maintain safety of the distribution system	Ensuring that our customers are able to access specific information will assist us in delivering safety benefits.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	We are proposing a medium-weight touch, mainly online, as this is the medium that will be used for the self-service technologies. All planned advertising will be prices at market rates. The weightings have all been modelled on a pragmatic level of spend to apply a prudent and efficient approach.
Cost that a prudent operator would require to achieve the objectives	We consider that our approach of getting awareness up initially then tapering off advertising campaigns in the 2015-20 RCP is required for us to appropriately discharge these responsibilities and reflects what a prudent operator would do to meet the needs of customers.
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the objectives.

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.6 – SA Power Networks: Customer Service Strategy 2014-2020
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 – SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Attachment 14.1 - SA Power Networks: Customer (Service) Technology Plan 2014-2024
- Supporting Document 21.25 – SA Power Networks: Communications Plan

3.2.3 Customer Service team

Reference	
Proposal Section	21.6.3
SEM Category(s)	A-34 Business Improvement
Regulatory Driver(s)	Change in Operating Environment
Forecast: 2015-2020 (June 15 $)	$1.6m

Category Function Overview
Since privatisation in 1999, SA Power Networks has undertaken the consolidation of its customer service operations and put in place measures to monitor customer satisfaction with its delivery of core customer services. As we look forward to the future, our vision is to ensure our customers are key influencers in our business direction and in the design of products and services they value.

To achieve this, the new Customer Service Strategy was 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 initiatives that meet emerging customer needs:

Our five strategic initiatives for 2014-2020 are as follows:

1. Be recognised as a national leader in the delivery of safe, reliable and quality power;
2. Manage and maintain a cost effective and relevant network that caters for a diverse range of electricity consumers;
3. Proactively seek opportunities to make a positive connection with communities and business across metropolitan and rural South Australia;
4. Deliver customer service that is tailored and responsive to immediate and changing needs; and
5. Be a trusted source of advice and information for customers' current and future electricity needs.

Description of the Change
One of the key focus areas of the fourth strategic initiative "*Deliver customer service that is tailored and responsive to immediate and changing needs,"* is our organisational culture and structure. The right customer service culture is critical to how well we understand our corporate direction, how actively we keep the voice of the customer at the centre of what we do, and how well we work together to deliver on the strategic initiatives.

With all the right tools, we still need the right behaviours to deliver on our commitments to customers, ensuring employees are set up to succeed.

While we have conducted various campaigns to improve customer service in targeted areas, we do not have a specific customer service training programme for all employees and contractors, and there is often an unclear picture of how the work of each employee or team(s) contributes to the end customer experience. To achieve success and improve the delivery and efficiency of the customer experience, we need to develop and implement the appropriate frameworks to cover our full end to end service delivery.

The Customer Relations department's dual roles of developing strategy and managing customer enquiries and complaints does not provide the resourcing levels required to provide the professional support services that are needed to deliver tailored training and dedicated support to other work teams, and has no contribution to the design of products and services for customers. Customer Relations is currently limited to defining the desired direction, and identifying major pain points for corrective action, the success of which can be variable without a holistic approach to end to end customer service delivery including the design of our products and services.

We are proposing to engage additional resources to support ongoing:

- engagement with customers and stakeholders;
- organisational improvements in customer service; and
- improvements to systems and processes.

Without a dedicated support team, improvement plans tend to be ad hoc, and lack the visibility to all employees that would fully engage them as being responsible for the customer service we collectively deliver.

We will introduce, for the first time, a dedicated customer experience improvement team. Members of this team will have the responsibility for developing customer service capability across the organisation, and 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 ensures the alignment of the Customer Service Strategy with the corporate strategy. Greater alignment and cohesiveness will be more cost-efficient, targeting the right measures and avoiding duplication.

What our stakeholders and customers have said to us

Our Customer Engagement Program confirmed that:

- customers have new expectations about how and when we communicate with them and they want more information about the electricity industry;
- 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;
- customers want more choice in how they interact with us;
- customers increasingly value self-service technologies and access to information and services wherever they are;
- 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; and
- raising community awareness through engagement, education and partnerships is essential.

Costing Methodology/Build Up
The additional resources will need specialised expertise and will be required to commence from mid-2016.

No double counting of opex (eg output/scale)
This is a new initiative and costs have not been incurred in our base year costs. Consequently, there is no duplication of costs associated with this in regard to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	**N/A**
Materials	N/A	N/A	N/A	N/A	N/A	**N/A**
Services	N/A	N/A	N/A	N/A	N/A	**N/A**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	0.413	0.413	0.413	0.413	**1.652**
Materials	-	-	-	-	-	**-**
Services	-	-	-	-	-	**-**
Total	**-**	**0.413**	**0.413**	**0.413**	**0.413**	**1.652**

Options Analysis

Option 1 – Business as Usual (Do Nothing)
The evaluation of the Do Nothing Option forms the baseline for decision making and is evaluated to understand the risks and impacts associated with maintaining existing 'business as usual' operations. The continuation of 'business as usual' (BAU) will result in adverse impacts to the business if this option is adopted.

The continuation of 'business as usual' would mean that no additional funding or resourcing is available and would require the limited resource availability within the Customer Relations department to continue working with other stakeholders to achieve the same goals, however the timeframe to see results will be significantly extended or worse, if we don't progress strategic imperatives identified above, at all.

The Do Nothing approach erodes customer satisfaction and the realisation of benefits and efficiencies and better and more efficient service delivery over time. Market research suggests customers have increasing expectations based on their experience with other industries such as retail and banking with sophisticated technology, communications, and self-service and self-management options. In terms of electricity distribution, customers do not make the distinction of it being a monopoly with regulated income; they benchmark service against their experiences with other organisations, against the total costs of the power, and in consideration of electricity being an essential part of their modern life, and demanding 24/7 access to information about that service provision.

Technology improvements are just one of many factors that deliver an overall improved experience. Process and cultural improvements are required concurrently to ensure the quality and accuracy of information we provide to customers, as well as support for self-service technologies.

The Do Nothing approach also erodes employee morale and their delivery of good customer service as employee initiatives for improvements are not implemented, or are only implemented in ad hoc ways or in small groups so benefits are not fully realised.

The Do Nothing approach continues a culture that sees customer service as the responsibility of the Customer Relations department, and not a whole of business objective that ultimately delivers benefits and efficiencies for consumers and the business. It continues to ignore the link between the products and services we design and how customers will experience it so customer interaction points are not mapped in our processes apart from the obvious touch points with Contact Centres.

The Do Nothing approach inhibits improved collaboration with our contractors who provide critical customer services such as meter reading, vegetation management, powerline construction and maintenance services, and public lighting maintenance. It also inhibits improved relationships, processes, and integration of systems with other industry participants such as councils and retailers with whom we share mutual customers who get lost in the gaps between service boundaries.

Options 1 - Benefits

There are no benefits associated with the Do Nothing option.

Option 1 - Risks

Table 10 Option 1 – Major Business Risks

Risk Description (Risk Line Item)	Consequence Description	Inherent Likelihood	Inherent Consequences	Risk Rating
Customer satisfaction declines when customer improvement not fully implemented across the organisation	• Lower customer satisfaction results • Increased complaints	Likely (4)	Moderate (3)	HIGH
Do not fully achieve regulatory requirements to engage meaningfully with customers	• Regulatory intervention	Possible (3)	Moderate (3)	MEDIUM (6)

Risk Description (Risk Line Item)	Consequence Description	Inherent Likelihood	Inherent Consequences	Risk Rating
Continuation of constrained customer service capabilities	• Customers forego benefits of SA Power Networks developing as an advanced customer centric DNSP.	Possible	Moderate	Medium

Option 2 – Preferred Option
This option would see the creation of a customer experience improvement team within the Customer Relations department.

Option 2 - Benefits
We mature to being a customer-centric organisation where customers co-design products and services to ensure, as far as possible, that we get them right the first time without needing expensive and inefficient enhancements and retrofits, or providing a degraded service. Employees and contractors are set up to succeed and have effective pathways for initiating and implementing change in multi-functional and cross-functional settings. As more employee initiatives for customer service improvements are realised, it will create positive momentum for further change which is presently stifled in an environment where everybody is busy with BAU and has no time to make more than superficial changes to the way we do things.

The Customer Experience Team will ensure alignment across all organisational goals so customer service standards are included in procurement activities, contractors and suppliers are fully engaged with delivering exceptional customer service, and our systems and processes across the full supply chain and service boundaries are developed to ensure great customer outcomes.

Ultimately, employees will be empowered and capable to always put customers first and implement appropriate change, but this is expedited in the first five years with the professional support of the Customer Experience Team.

The Customer Experience Team will also work with employees, contractors, and directly with customers to ensure that we are also effectively able to use customer intelligence to deliver improved services in areas where human knowledge, rather than technology, provides critical information, for example, about our network in areas without automation or 'smarts', or local development plans.

Benefits	Consequence outcome
Voice of customer integration into SA Power Networks' activities and processes is more fully enabled.	• Appropriate implementation of the Customer Service Strategy • Early and ongoing support to our desired customer service culture, contribution to SA Power Networks' ongoing development as a customer centric DNSP
Employees have the appropriate training and support to deliver sustainable improvements in customer service.	• Improved customer satisfaction survey results • Improved customer perception of "Value for Money" • Improved internal employee satisfaction
Achieve regulatory requirements to engage meaningfully with customers	• Compliance with regulatory obligations
Alignment with corporate quality processes, cost efficiency in planning and delivering services to customers	• Prudent service delivery expenditure

Option 2 - Risks

There are no risks associated with this option.

Alignment with NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Our customers have increasing expectations in their interactions with us and in relation to our delivery of services to them. A prudent and efficient Customer Experience Improvement Team will support our ability to prudently and efficiently meet and manage demand for standard control services.
Comply with all applicable regulatory obligations or requirements	We have a number of regulatory obligations in relation to the provision of standard control services, and having a prudent and efficient Customer Experience Improvement Team will assist us in meeting those obligations.
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	Ensuring that our customers are able to interact with, and gain appropriate information from SA Power Networks (enabled by enhanced processes as promoted by our Customer Experience Improvement Team) will assist us in maintaining quality, reliability and security of supply.
Maintain safety of the distribution system	Ensuring that our customers are able to interact with, and gain appropriate information from SA Power Networks (enabled by enhanced processes as promoted by our Customer Experience Improvement Team) will assist us in delivering safety benefits.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach ensures that employees have the appropriate training and support to deliver sustainable improvements in customer service and cost efficiencies over time.
Cost that a prudent operator would require to achieve the objectives	We consider that our service delivery expenditure is prudent as aligning corporate quality processes and cost efficiency in planning and delivering services to customers will ensure we are able to deliver benefits to consumers consistently over time. Our comprehensive Customer Engagement Program and further engagement in support whilst developing our Customer Service Strategy, strongly indicates that our approach is prudent.
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the objectives.

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.6 – SA Power Networks: Customer Service Strategy 2014-2020
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 – SA Power Networks: Directions and Priorities 2015 to 2020 consultation document

3.3. Community safety

3.3.1 Bushfire

Reference	
Proposal Section	21.6.3
SEM Category(s)	A-3 Communications
Regulatory Driver(s)	Compliance with Legal and Regulatory Obligations; Change in Community Expectation
Forecast: 2015-2020 (June 15 $)	$2.6m

Category Function Overview
New summer time media campaigns to better educate our customers about the bushfire dangers with respect to power lines and outages.

Description of the Change
Throughout our lengthy and thorough Customer Engagement Program, customers overwhelmingly indicated that public safety, particularly with respect to bushfires, is a key priority area that we must address across the entire State.

As highlighted by the recent CSIRO and Bureau of Meteorology (**BoM**) reports, extreme fire weather conditions are on the increase in South Australia. Climate change is increasing the frequency of very hot days and will very likely lead to increased frequencies of days with extreme fire danger in bushfire risk areas.

What our stakeholders and customers have said to us
Our Customer Engagement Program confirmed that:

- customers rated the top 3 community safety and reliability initiatives as:
  - inspecting, maintaining and upgrading the network;
  - bushfire prevention activities; and
  - hardening the network against lightning and storms;
- customers strongly supported initiatives that would result in the prevention of bushfires, safety hazards and provide valued support for the community in emergency situations;
- 90% of customers supported a more reliable power supply to CFS Bushfire Safer Places;
- 90% support SA Power Networks further increasing its inspection, maintenance and construction standards in bushfire risk areas in order to minimise the probability of fires starting from power lines;
- customers rated building powerlines less prone to fire starts and ensuring bushfire safer places have continuous power supply as the two highest bushfire management initiatives;
- customers increasingly value self-service technologies and access to information and services wherever they are; and
- 61% of customers surveyed said we should be proactive and responsive, and continue to improve our interactions with them.

Proposed Activity

To date we have taken a fairly low-key approach with bushfire awareness and advertising, centred only on South Australia's high bushfire risk areas. The approach has been extremely reactive and based on catastrophic fire danger days only.

Through our customer engagement work we have come to understand that we have a greater number of customer groups that we need to be talking to:

- many people live in non-bushfire areas but are served by lines going through high bushfire risk areas;
- more people have holiday homes and are travelling to and through bushfire risk areas, and staying in unfamiliar surroundings;
- businesses need greater levels of communication as they have workplace safety obligations; and
- people that live in metropolitan Adelaide need additional communication about heatwaves.

Therefore, we are proposing a broader media campaign, targeted in the summer months (Nov-Jan) 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 with respect to powerlines and outages. We will also work with key stakeholders to communicate with specific target markets in the lead up to summer.

The additional activity includes:

- An annual 3-month media campaign, particularly focussed on bushfire regions, with varying levels of spend each year. Proposed media includes:
    - Metropolitan/regional TV;
    - Metropolitan/regional press;
    - Metropolitan/regional radio;
    - Regional outdoor; and
    - Digital.

- The advertising campaigns also include numerous bursts of advertising activity on press and radio prior to catastrophic fire days and a particular focus on high risk bushfire days in connection with powerlines and how to remain safe.

- A small amount of additional cost has been included to refresh and update all our bushfire printed materials which are sent to an even wider group of customers due to the numbers of people potentially affected by bushfires.

Given the additional customer groups with whom we need to communicate, we have selected broader media channels in order to reach more people. For example, we are planning some outdoor media for the first time, aimed at people travelling along roads to and through high bushfire risk areas to holiday homes, and targeting holiday home owners via metropolitan media.

To respond to the increased likelihood of extreme fire danger days due to climate change, we are planning more proactive advertisements that can be placed into key media within 24 hours, which will allow us to be far more responsive to extreme weather events such as catastrophic fire days and impending heat waves.

The types of messages our communications will carry are:

- preparation of bushfire action plans that take into account the potential loss of electricity supply;
- consideration of alternative sources of power for pumping water and operating fire-fighting equipment;
- how to prepare for an outage;
- what to do in an outage; and
- education around prolonged outages, particularly on high fire risk days.

More information on the proposed campaign including detailed costings, are provided in the Communication Plan 2014-2020.

Costing Methodology/Build Up
Our media schedule has been worked out very carefully with our media buying agency and creative agency. Whilst suggesting a lot more than we have done in the past, we're proposing a medium-weight touch to build strong levels of reach and frequency, ensuring that the broad community can be informed of all the safety requirements. The weightings have all been modelled on a pragmatic level of spend, therefore applying a prudent and efficient approach.

Where possible we will be taking maximum advantage of new digital technologies, which provide a cheaper alternative to the more traditional media channels. However, we recognise that TV advertising is still one of the most effective ways of communicating with our target markets therefore for the first time we are proposing some metropolitan TV advertising in our media mix, in addition to metropolitan radio and metropolitan press advertising.

A slightly heavier bushfire advertising program is proposed in 2016 and 2017 to raise awareness levels more quickly, responding to customers citing bushfire safety as a high priority. The campaigns will drop back in 2018 and 2020 with a slightly heavier schedule by way of reminder in 2019. We have allowed for 5 bursts of tactical press and radio advertising prior to catastrophic fire days to allow for more specific communications.

The advertising costs are mainly for campaigns running through November to January. A small amount of additional graphic design cost has been included in 2016 and 2019 to refresh the bushfire printed materials to reflect the additional messages we now need to convey and the additional customer segments these need to go to.

All costings adopt current market rates.

No double counting of opex (eg output/scale)
This is a new initiative and costs have not been incurred in our base year. Consequently, there is no duplication of costs associated with this in regard to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	**N/A**
Materials	N/A	N/A	N/A	N/A	N/A	**N/A**
Services	N/A	N/A	N/A	N/A	N/A	**N/A**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services	0.746	0.547	0.360	0.552	0.360	**2.565**
Total	**0.746**	**0.547**	**0.360**	**0.552**	**0.360**	**2.565**

Options Analysis

Option 1 Business as Usual (Do Nothing)

Doing nothing is not recommended. We have a regulatory obligation to communicate safety risks to our customers. Furthermore, our Customer Engagement Program has clearly demonstrated a high demand for taking prudent steps to mitigate community risks arising from bushfires as they relate to our infrastructure. This extends to appropriate communications related to these matters, so omitting appropriate communication does not align with customer preferences.

Option 2 - Preferred Option

The preferred option is to communicate in order to educate our customers with regard to dangers arising from bushfires as they relate to our infrastructure. This also aligns to clear customer preferences, and is consistent with the increasing risk from bushfires as detailed in our Regulatory Proposal (Chapter 11).

With the likely increase in bushfires and heatwaves, more customers will become affected than in previous years. Even if they don't live in bushfire areas, more people are living near bushfire areas or purchasing holiday homes in bushfire areas.

The additional communication activities planned will result in the following:

- reduces potential safety issues in the community;
- reduces customer confusion;
- gives our customers more information and improves service levels, which is likely to increase satisfaction; and

- helps customers be better prepared for outages.

We note that bushfire safety is also very prominent in the communication activities of other DNSPs such as ActewAGL, Endeavour Energy, Energex, Essential Energy, SP AusNet, United Energy Distribution, and Powercor.

A three month advertising campaign will ensure that we cover the summer months without over-communicating, and by 'winding back' the campaign in 2018 and 2020 we will ensure the safety messages are not lost but still remain relevant and effective.

Alignment with NER expenditure objectives & criteria
Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	A bushfire can adversely impact on SA Power Networks' ability to meet or manage expected demand for standard control services, and so better informing customers about bushfire action plans and outages will assist us to meet and manage that demand.
Comply with all applicable regulatory obligations or requirements	SA Power Networks has a duty to take reasonable steps to ensure that our distribution system is safe and safely operated and to maintain our distribution system in accordance with good industry practice. In addition, we are required under the conditions of our Distribution Licence and Section 25 of the *Electricity Act* to prepare and comply with a Safety, Reliability, Maintenance and Technical Management Plan (**SRMTMP**) that lays out the safety and technical compliance management framework agreed between the South Australian Office of the Technical Regulatory and us, and approved annually by the Essential Services Commission of South Australia. Regulation 72(2) of the *Electricity (General) Regulations* sets out a number of matters that must be dealt with by the SRMTMP. These matters include: • the communication of information to the public for the purpose of reducing the risk of death or injury, or damage to property, arising out of the operation of SA Power Networks' electricity infrastructure; and • the communication of information to existing and potential customers about the facilities that customers must provide for connection to the network and procedures that customers must follow in order to prevent damage to or interference with the network. Better educating our customers about the dangers and implications of bushfire risks, as well as risk mitigation steps they can take and strategies they can implement, is required in order for us to appropriately discharge these obligations.

Operating Expenditure Objectives	Considerations
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	Having better informed customers about the dangers and implications of bushfires and actions to be taken before and when bushfires occur will assist us to maintain quality, reliability and security of supply.
Maintain safety of the distribution system	Having better informed customers about the dangers and implications of bushfires and actions to be taken before and when bushfires occur will assist us to maintain public safety and safety of the distribution system, and thereby reduce the costs associated with bushfires.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach enables us to better educate customers about the dangers of bushfires and respond to the increased likelihood of extreme fire days due to climate change, at the lowest cost. All advertising will be priced at market rates. Proper preparation for bushfires by SA Power Networks and customers will also minimise the risk of damage to the network and surrounding areas that might be incurred on high bushfire risk days.
Cost that a prudent operator would require to achieve the objectives	We consider that our approach is required for us to appropriately discharge our responsibilities and reflects what a prudent operator would do to comply with safety, quality, reliability and security of supply obligations so far as they relate to bushfires. Bushfire safety is very prominent in the communication activities of most other DNSPs such as ActewAGL, Endeavour Energy, Energex, Essential Energy, SP AusNet, United Energy Distribution, and CitiPower/Powercor.
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the objectives.

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 – SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Attachment 10.1 – Bureau of Meteorology (**BoM**), Climate Extremes Analysis for South Australian Power network Operations
- Attachment 10.2 – CSIRO and BoM: State of the Climate 2014
- Supporting Document 21.25 – SA Power Networks: Communications Plan 2014-2020

3.3.2 Extreme Weather

Reference	
Proposal Section	21.6.3
SEM Category(s)	A-3 Communications
Regulatory Driver(s)	Compliance with Legal and Regulatory Obligations; Change in Community Expectation
Forecast: 2015-2020 (June 15 $)	$1.9m

Category Function Overview
New broad media campaign to better educate our customers about the dangers and implications of extreme weather outages and fallen power lines.

Description of the Change
Throughout our lengthy and thorough Customer Engagement Program, customers indicated that public safety is a key priority area that we must address across the entire State.

Climate change is already increasing the intensity and frequency of many extreme weather events across Australia. In February 2014 we experienced one of the most significant storms to hit our network in recent history, with some 90,000 affected customers without power for more than twelve hours. Fortunately, no one was injured as a result of the damaged network. However, we need to better prepare our customers for more extreme weather conditions in the future.

What our stakeholders and customers have said to us
Our Customer Engagement Program confirmed that:

- customers rated the top 3 community safety and reliability initiatives as:
- inspecting, maintaining and upgrading the network;
- bushfire prevention activities; and
- hardening the network against lightning and storms;
- customers strongly supported initiatives that would result in the prevention of bushfires, safety hazards and provide valued support for the community in emergency situations;
- customers increasingly value self-service technologies and access to information and services wherever they are; and
- 61% of customers surveyed said we should be proactive and responsive, and continue to improve our interactions with them.

Proposed Activity
To date, we have done very little awareness or advertising around safety and outages in times of extreme weather, other than the low key and reactive approach for bushfires as mentioned in the previous section.

We are proposing a broad media campaign, targeted in the winter months when extreme weather events like storms and high winds are more prominent, to better educate our customers about the dangers and implications of extreme weather outages and fallen power lines. We will also 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, because the greater concentration of population in metropolitan areas means that safety around fallen power lines is of more concern.

We will also work with key stakeholders to communicate with specific target markets in the lead up to winter.

The additional activity includes:

- An annual three month media campaign, particularly focussed on metropolitan areas, with varying levels of spend each year. Proposed media includes:
    - Metropolitan/regional TV;
    - Metropolitan/regional press;
    - Metropolitan/regional radio; and
    - Digital.

- The advertising campaigns will also include numerous bursts of advertising activity on press and radio in times of extreme weather (e.g. storms).

The types of messages our communications will carry are:

- 'Do not touch or move' warnings for fallen power lines or anything that comes into contact with them, and avoidance of fallen or uprooted trees;
- how to prepare for an outage;
- what to do in an outage; and
- education around prolonged outages.

For more information on the proposed campaign including detailed costings, see the Communication Plan 2014-2020.

Costing Methodology/Build Up

Our media schedule has been worked out very carefully with our media buying agency and creative agency. Whilst suggesting a lot more than we have done in the past, we're proposing a medium-weight touch to build strong levels of reach and frequency, ensuring that the broad community can be informed of all the safety requirements. The weightings have all been modelled on a pragmatic level of spend, therefore applying a prudent and efficient approach.

Where possible we are taking maximum advantage of new digital technologies, which provide a cheaper alternative to the more traditional media channels. However, we recognise that TV advertising is still one of the most effective ways of communicating with our target markets therefore we are proposing some metropolitan TV advertising in our media mix, in addition to metropolitan radio and metropolitan press advertising.

A slightly heavier extreme weather advertising program is proposed in 2016 and 2017 to raise awareness levels more quickly, responding to customers citing community safety as a high priority. The campaigns drop back to a 'maintenance' mode for the remaining years of the RCP. We have allowed for 5 bursts of tactical press and radio advertising per year so we are more responsive to extreme weather events (e.g storms).

All costings adopt current market rates.

No double counting of opex (eg output/scale)
This is a new initiative and costs have not been incurred in our base year. Consequently, there is no duplication of costs associated with this in regard to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	**N/A**
Materials	N/A	N/A	N/A	N/A	N/A	**N/A**
Services	N/A	N/A	N/A	N/A	N/A	**N/A**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services	0.648	0.462	0.273	0.222	0.273	**1.878**
Total	**0.648**	**0.462**	**0.273**	**0.222**	**0.273**	**1.878**

Options Analysis

Option 1 – Business as Usual (Do Nothing)
Doing nothing is not recommended. We have a regulatory obligation to communicate safety risks to our customers. Furthermore, our Customer Engagement Program has clearly demonstrated a high demand for prudent steps to mitigate community safety risks, including those arising from extreme weather. This extends to appropriate communications related to these matters, so omitting appropriate communication does not align with customer preferences.

Option 2 - Preferred Option
The preferred option is to communicate in order to educate our customers with regard to dangers and implications arising from extreme weather events and fallen power lines. This aligns to clear customer preferences, and is consistent with the increasing frequency and severity of extreme weather events as detailed in our Regulatory Proposal (Chapter 12).

The additional communication activities planned will result in the following:

- reduces potential safety issues in the community;
- reduces customer confusion;
- gives our customers more information and improves service levels, which is likely to increase satisfaction; and

- helps customers be better prepared for outages.

We note that extreme weather campaigns are also very prominent in the communication activities of other DNSPs such as ActewAGL, Aurora Energy, AusGrid, CitiPower/Powercor, Endeavour Energy, Energex, Ergon Energy, Horizon Power, Jemena, Power and Water Corporation and SP AusNet.

A three month advertising campaign will ensure that we cover the winter months without over-communicating, and by 'winding back' the campaign in 2018 - 2020 we will ensure the safety messages are not lost but still remain relevant and effective. We have also incorporated a saving on advertising production costs where possible by recycling general messages around outages, which can be shared with bushfire advertising.

Alignment with NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	An extreme weather event can adversely impact on SA Power Networks' ability to meet or manage expected demand for standard control services, and so better informing customers about such events and outages will assist us to meet and manage that demand.
Comply with all applicable regulatory obligations or requirements	SA Power Networks has a duty to take reasonable steps to ensure that our distribution system is safe and safely operated and to maintain our distribution system in accordance with good industry practice. In addition, we are required under the conditions of our Distribution Licence and Section 25 of the *Electricity Act* to prepare and comply with a Safety, Reliability, Maintenance and Technical Management Plan (**SRMTMP**) that lays out the safety and technical compliance management framework agreed between the South Australian Office of the Technical Regulatory and us, and approved annually by the Essential Services Commission of South Australia. Regulation 72(2) of the *Electricity (General) Regulations* sets out a number of matters that must be dealt with by the SRMTMP. These matters include: • the communication of information to the public for the purpose of reducing the risk of death or injury, or damage to property, arising out of the operation of SA Power Networks' electricity infrastructure; and • the communication of information to existing and potential customers about the facilities that customers must provide for connection to the network and procedures that customers must follow in order to prevent damage to or interference with the network. Better educating our customers about the dangers and implications of extreme weather events, as well as risk mitigation steps they can take and strategies they can implement, is required in order for us to appropriately discharge these obligations.

Operating Expenditure Objectives	Considerations
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	Having better informed customers about the dangers and implications of extreme weather events, and actions to be taken before and when such events occur, will assist us to maintain quality, reliability and security of supply.
Maintain safety of the distribution system	Having better informed customers about the dangers and implications of extreme weather events, and actions to be taken before and when such events occur, will assist us to maintain public safety and safety of the distribution system, and thereby reduce the costs associated with such events.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach enables us to better educate customers about the dangers of extreme weather events and respond to the increased likelihood of those events due to climate change, at the lowest cost. All planned advertising will be priced at market rates. Proper preparation for extreme weather events by SA Power Networks and customers will also minimise the damage to the network and surrounding areas that might be incurred on extreme weather days.
Cost that a prudent operator would require to achieve the objectives	We consider that our approach is required for us to appropriately discharge these responsibilities and reflects what a prudent operator would do to comply with its safety and quality, reliability and security of supply obligations so far as they relate to extreme weather events. Extreme weather campaigns are also very prominent in the communication activities of a significant number of DNSPs such as ActewAGL, Aurora Energy, AusGrid, CitiPower/Powercor, Endeavour Energy, Energex, Ergon Energy, Horizon Power, Jemena, Power and Water Corporation and SP AusNet.
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the objectives.

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte: SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 - SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Supporting Document 21.25 – SA Power Networks Communications Plan 2014-2020

3.3.3 Farmers and Sailors

Reference	
Proposal Section	21.6.3
SEM Category(s)	A-3 Communications
Regulatory Driver(s)	Compliance with Legal and Regulatory Obligations; Change in Community Expectation
Forecast: 2015-2020 (June 15 $)	$0.9m

Category Function Overview
Incremental programs targeting farmers and sailors with respect to the risks of equipment coming into contact with power lines.

Description of the Change
Throughout our lengthy and thorough Customer Engagement Program, customers indicated that public safety is a key priority area that we must address across the entire State.

Two target groups that need to take additional care around powerlines are farmers (with their farm machinery) and sailors (with their boat masts). Farmers are using bigger machinery nowadays 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 powerlines. Similarly, recreational sailors manoeuvring yachts with tall masts could come into contact with powerlines. Farmers and sailors are a very niche customer segment, but they can be spread out across diverse locations. Safety remains our number one priority with this group, particularly as we are still seeing some farming accidents.

What our stakeholders and customers have said to us
Our Customer Engagement Program confirmed that customers strongly supported initiatives that would result in the prevention of bushfires, safety hazards and provide valued support for the community in emergency, and 61% of customers surveyed said we should be proactive and responsive, and continue to improve our interactions with them.

Proposed Activity
To date, we have done very little awareness or advertising aimed at farmers and sailors in relation to safety. We are proposing a highly targeted media campaign aimed specifically at farmers and sailors, over a 4-6 week period to be timed with their most active periods. 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 which targets their families.

The additional activity includes:

- A light but targeted annual media campaign. For farmers the proposed media includes:
    - Agricultural publications;
    - Regional TV;
    - Regional radio; and
    - Digital for example farming websites.

For sailors the proposed media includes:
  - Boating publications;
  - Digital for example weather, tidal websites; and
  - Supplemented by low-cost public relations activities with sailing clubs, for example.
- A small amount of additional cost has been included to issue communication materials direct to farmers.

The types of messages our communications will carry are:
- Ensuring vehicles like farm machinery, trucks and boats don't come into contact with power lines; and
- Reminder on national initiatives, such as Dial Before You Dig.

For more information on the proposed campaign including detailed costings, see the Communication Plan 2014-2020.

Costing Methodology/Build Up
Our media schedule has been worked out very carefully with our media buying agency and creative agency. Whilst suggesting more advertising than we've done in the past, it is very targeted advertising aimed specifically at farmers and sailors. It will last no longer than 6 weeks and be timed prior to busy times with farmers (e.g. harvest) and the summer season for sailors. The weightings have all been modelled on a pragmatic level of spend, therefore applying a prudent and efficient approach.

Where possible we will be taking maximum advantage of new digital technologies, which provide a cheaper alternative to the more traditional media channels. However, we recognise that one of the best ways of reaching farmers and their families is through more expensive regional TV and radio TV advertising. We will also be taking every advantage of the targeted publications aimed specifically at farmers and sailors, ensuring there is no wastage in readership.

The costs around communication materials are based on mailing one third of the 13,475 farms in South Australia, employing 33,000 per annum. Having some direct marketing ensures that messages are received by farmers more directly. We intend to take advantage of the rationalisation of industry bodies in the primary production sector, giving us a more concentrated route to market. The levels of spend are proposed to be similar each year to ensure consistency of message.

No double counting of opex (eg output/scale)
This is a new initiative and costs have not been incurred in our base year costs. Consequently, there is no duplication of costs associated with this in regard to output growth.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	N/A	N/A	**N/A**
Materials	N/A	N/A	N/A	N/A	N/A	**N/A**
Services	N/A	N/A	N/A	N/A	N/A	**N/A**
Total	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

'N/A' or 'Not Applicable' indicates that no costs were incurred in the relevant regulatory year in relation to this type of activity because this type of activity was not undertaken during that regulatory year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services	0.249	0.156	0.179	0.156	0.179	**0.919**
Total	**0.249**	**0.156**	**0.179**	**0.156**	**0.179**	**0.919**

Options Analysis

Option 1 – Business as Usual (Do Nothing)
Doing nothing is not recommended. We have a regulatory obligation to communicate safety risks to our customers. Furthermore, our Customer Engagement Program has clearly demonstrated a high demand for prudent steps to mitigate community safety risks, including those arising from customer activities where there is heightened potential for customer equipment coming into contact with our infrastructure. This extends to appropriate communications related to these matters, so omitting appropriate communication does not align with customer preferences.

Option 2 - Preferred Option
The preferred option is to communicate in order to educate our customers with regard to dangers and implications arising from customer activities where there is heightened potential for customer equipment coming into contact with our infrastructure. This also aligns to clear customer preferences.

The additional communication activities planned will result in the following:

- reduces potential safety issues in the farming and boating communities
- gives our customers more information and improves service levels, which is likely to increase satisfaction.

We note that similar campaigns are also very prominent in the communication activities of other DNSPs such as Aurora Energy, AusGrid, Endeavour Energy, Energex, Ergon Energy, Essential Energy and Power and Water Corporation.

We are taking advantage of having such specific target markets by only proposing a light advertising schedule over 4 to 6 weeks, and we're only adopting a direct marketing approach because we are able to take advantage of a very prudent channel to market; namely the industry body for farmers.

Alignment with NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand	An incident involving a power line can adversely impact on SA Power Networks' ability to meet or manage expected demand for standard control services, and so better informing farmers and sailors about the dangers of power lines and risks associated with some of their actions, will assist us to meet and manage that demand.
Comply with all applicable regulatory obligations or requirements	SA Power Networks has a duty to take reasonable steps to ensure that our distribution system is safe and safely operated and to maintain our distribution system in accordance with good industry practice. In addition, we are required under the conditions of our Distribution Licence and Section 25 of the Electricity Act to prepare and comply with a Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP) that lays out the safety and technical compliance management framework agreed between the South Australian Office of the Technical Regulatory and us, and approved annually by the Essential Services Commission of South Australia. Regulation 72(2) of the Electricity (General) Regulations sets out a number of matters that must be dealt with by the SRMTMP. These matters include the communication of information to the public for the purpose of reducing the risk of death or injury, or damage to property, arising out of the operation of SA Power Networks' electricity infrastructure. Better educating farmers and sailors (who are particularly at risk) about the dangers of power lines as well as risk mitigation steps they can take and strategies they can implement, is required in order for us to appropriately discharge these obligations.
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	Having farmers and sailors who are better informed about the dangers of power lines and precautions they can take, will assist us to maintain quality, reliability and security of supply.
Maintain safety of the distribution system	Having farmers and sailors who are better informed about the dangers of power lines and precautions they can take, will assist us to maintain their safety, the safety of the public generally, and safety of the distribution system, and thereby reduce the costs associated with incidents.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our approach enables us to better educate farmers and sailors, people who are particularly at risk, about the dangers of power lines, at the lowest cost. All planned advertising will be priced at market rates.
Cost that a prudent operator would require to achieve the objectives	We consider that our approach is required for us to appropriately discharge these responsibilities and reflects what a prudent operator would do to comply with its safety obligations so far as they relate to incidents involving power lines. Similar campaigns are very prominent in the communication activities of several other DNSPs such as Aurora Energy, AusGrid, Endeavour Energy, Energex, Ergon Energy, Essential Energy and Power and Water Corporation.
Realistic expectation of demand and cost inputs required to achieve the objectives	We have carefully assessed the resources required to efficiently and prudently achieve the objectives.

Supporting Documentation/Evidence

- Attachment 6.3 – Deloitte; SA Power Networks Stage 1 Stakeholder & Consumer Workshop Report
- Attachment 6.5 – Deloitte: SA Power Networks Stage 1 Online Consumer Survey Report
- Attachment 6.7 – Deloitte: SA Power Networks Stage 2 Stakeholder & Consumer Workshop Report
- Attachment 6.10 - SA Power Networks: Directions and Priorities 2015 to 2020 consultation document
- Supporting Document 21.25 – SA Power Networks: Communications Plan

4. Finance 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 11 outlines these step change expenditures for the 2015-20 RCP with the subsequent sections providing details of the individual step changes.

Table 11: Insurance premiums and superannuation SCS 2015-20 RCP

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.

4.1. Insurance premiums

Reference	
Proposal Section	21.6.4
SEM Category(s)	DA-22
Regulatory Driver(s)	Finance/Economic
Forecast: 2015-2020 (June 15 $)	$3.0m

Description of the Change

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 SA Power Networks risk profile.

Costing Methodology/Build Up

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.

No double counting of opex (eg output/scale)

This is a zero based calculation with the costs incremental to the 2013/14 base year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services	0.257	0.429	0.600	0.761	0.917	**2.964**
Total	**0.257**	**0.429**	**0.600**	**0.761**	**0.917**	**2.964**

Alignment with NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Maintaining adequate and appropriate insurances as a measure to address risk and events that are outside SA Power Networks' control, is fundamental to our ability to meet and manage the expected demand for standard control services.
Comply with all applicable regulatory obligations or requirements	Maintaining adequate and appropriate insurances is necessary in order for us to meet a range of our regulatory obligations.
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	Maintaining adequate and appropriate insurances is necessary in order for us to maintain quality, reliability and security of supply of standard control services.
Maintain safety of the distribution system	Maintaining adequate and appropriate insurances is necessary in order for us to maintain the safety of the distribution system.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our forecast insurance premiums reflect the best available given our risk profile.
Cost that a prudent operator would require to achieve the objectives	We consider that our insurances and their forecast premiums reflect those which a prudent operator would maintain and incur, particularly given that Aon is the insurance broker and risk management consultant to 65% of Australian DNSPs, is the leading Australian provider in this sector, and has detailed knowledge of our risk profile.
Realistic expectation of demand and cost inputs required to achieve the objectives	Industry expert Aon independently forecast our insurance premiums for the 2015-20 RCP.

Supporting Documentation/Evidence

- Attachment 21.1 – AON: Insurance Premium Forecast Report September 2014

4.2. Superannuation

Reference	
Proposal Section	21.6.4
SEM Category(s)	A-38
Regulatory Driver(s)	Finance/Economic
Forecast: 2015-2020 (June 15 $)	($2.4m)

Description of the Change
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 that will apply from 1 January 2015 are not known at the date of our Proposal, the contribution rates that currently apply have been used to calculate forecast superannuation contributions. The negative adjustments over the five year period, reflects the lower contributions that commenced part way through the 2013/14 base year, and total $2.4 million. Our Revised Proposal will incorporate the new contribution rates as determined by the EISS actuary and Board.

Costing Methodology/Build Up
Contributions have been calculated in 2015 dollars, based on payroll data as at April 2014, adjusted for the:

- Enterprise Bargaining increase scheduled for 2015; and
- Increase in employee numbers that has been applied as per the workforce FTE forecast. New employees are assumed to be members of the accumulation scheme (Division 5) as the defined benefit schemes are closed to new members.

Current superannuation contribution rates are applied to this forecast of future payroll costs to derive future cash contributions. These contributions are then allocated to Standard Control Services and Alternative Control Services capital and operating costs, consistent with the approved CAM.

No double counting of opex (eg output/scale)
This is a zero based calculation with the costs incremental to the 2013/14 base year.

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	(0.864)	(0.580)	(0.439)	(0.303)	(0.217)	**(2.403)**
Materials	-	-	-	-	-	**-**
Services	-	-	-	-	-	**-**
Total	**(0.864)**	**(0.580)**	**(0.439)**	**(0.303)**	**(0.217)**	**(2.403)**

Alignment with NER expenditure objectives & criteria

Our proposed approach aligns with the operating expenditure objectives set out in the NER as follows:

Operating Expenditure Objectives	Considerations
Meet or manage expected demand for SCS	Properly remunerated employees support our ability to meet and manage demand for standard control services.
Comply with all applicable regulatory obligations or requirements	SA Power Networks has a regulatory obligations to pay required employer superannuation contributions.
Where no applicable regulatory obligations or requirements exist, maintain quality, reliability and security of supply	Properly remunerated employees support our ability to maintain quality, reliability and security of supply.
Maintain safety of the distribution system	Properly remunerated employees support our ability to maintain the safety of the distribution system.

Our proposed approach aligns with the three operating expenditure criteria set out in the NER as follows:

Operating Expenditure Criteria	Considerations
Efficient cost of achieving the objectives	Our superannuation contributions reflect the minimum amounts payable by us.
Cost that a prudent operator would require to achieve the objectives	Our superannuation contributions are mandatory expenditure by us and would therefore be incurred by any DNSP in our position.
Realistic expectation of demand and cost inputs required to achieve the objectives	An independent actuarial review of our forecasts is currently being undertaken. We will include the outcome of this review in the Revised Proposal.

Supporting Documentation/Evidence

- Supporting Document 20.67 – SA Power Networks: Superannuation Contribution Calculations

5. Base Year and Adjustments

Base Year

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 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 have calculated a base year cost of $247.4m per annum, as shown in the following table.

Table 12: Derivation of SCS Base Year (excl Debt Raising)

	($m)
2013/14 Actual	234.9
Incremental 2014/15 Allowance	4.4
Escalation to June 15	8.1
Base Year	**247.4**

Base Year Adjustments

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 11 below summarises the adjustments to the base year expenditures for each regulatory year of the 2015–20 RCP for these items.

The background to the adjustments to the base year costs is discussed in detail below.

Table 13: Base Year cost adjustments for SCS 2015-2020

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)**	**2.1**	**(6.4)**	**(34.8)**

5.1. Self Insurance

Reference	
Proposal Section	21.5
SEM Category(s)	A-39 Self insurance
Regulatory Driver(s)	Base year adjustment
Forecast: 2015-2020 (June 15 $)	($16.1m)

Description of the Change

SA Power Networks 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.

Self-insurance costs are reported on a cash basis, consistent with the approved Cost Allocation Method (**CAM**). The self-insurance cash forecast relates to claims of $100,000 or greater arising from the above circumstances, and workers compensation claims. Amounts will vary from year to year, dependent on claims, and the base year has been adjusted to represent the average expenditure over the first four years of the current RCP.

Costing Methodology/Build Up

The 2013/14 base year cost for self-insurance is $5.1 million (June 2015 $), which is $3.2 million higher than the average expenditure over the first four years of the current RCP. The base year expenditure has consequently been reduced by this amount in the Proposal.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	-	-	-	-	-	-
Materials	-	-	-	-	-	-
Services	0.404	0.890	1.128	4.985	1.874	**9.281**
Total	**0.404**	**0.890**	**1.218**	**4.985**	**1.874**	**9.281**

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	-
Materials	-	-	-	-	-	-
Services	(3.215)	(3.215)	(3.215)	(3.215)	(3.215)	**(16.075)**
Total	**(3.215)**	**(3.215)**	**(3.215)**	**(3.215)**	**(3.215)**	**(16.075)**

Supporting Documentation/Evidence

- RIN 2.15

5.2. Metering Reclassification

Reference	
Proposal Section	21.5
SEM Category(s)	DA-23 Retail Contestability
Regulatory Driver(s)	Base year adjustment
Forecast: 2015-2020 (June 15 $)	($11.1m)

Description of the Change

In its 2010-15 Framework and Approach paper (**F&A**) the AER has reclassified Type 5 and 6 metering related services to ACS. The Type 6 metering reclassification primarily impacts on meter data management services relating to back office support information systems and personnel.

Costing Methodology/Build Up

The applicable base year cost to be transferred to ACS is $2.2 million. A corresponding increase has been included in ACS.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	0.381	0.381	**0.772**
Materials	N/A	N/A	N/A	-	-	-
Services	N/A	N/A	N/A	1.764	1.764	**3.528**
Total	**N/A**	**N/A**	**N/A**	**2.145**	**2.145**	**4.290**

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	(0.394)	(0.394)	(0.394)	(0.394)	(0.394)	**(1.970)**
Materials	-	-	-	-	-	-
Services	(1.823)	(1.823)	(1.823)	(1.823)	(1.823)	**(9.115)**
Total	**(2.217)**	**(2.217)**	**(2.217)**	**(2.217)**	**(2.217)**	**(11.085)**

Supporting Documentation/Evidence

- RIN 4.2

5.3. Regulatory Proposal

Reference	
Proposal Section	21.5
SEM Category(s)	A-6 Regulation
Regulatory Driver(s)	Base year adjustment
Forecast: 2015-2020 (June 15 $)	($8.4m)

Description of the Change

Our Regulatory Proposal for the 2015-20 RCP has involved considerable expense. The 2013/14 base year incorporates higher expenditure for preparation of that Proposal, and therefore a negative charge is applied for those years in the 2015-20 RCP during which such a level of expenditure will not be incurred.

Costing Methodology/Build Up

The 2013/14 base year adjustment equates to an average annual reduction of $1.6 million over the 2015-20 RCP.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	-	-	0.842	4.069	4.069	**8.980**
Materials	-	-	0.002	0.170	0.170	**0.342**
Services	-	-	0.217	0.840	0.840	**1.897**
Total	**-**	**-**	**1.061**	**5.079**	**5.079**	**11.219**

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	(2.863)	(3.069)	(1.240)	0.621	(1.240)	**(7.791)**
Materials	(0.124)	(0.175)	(0.175)	(0.020)	0.032	**(0.462)**
Services	(0.020)	(0.073)	(0.073)	0.062	(0.073)	**(0.177)**
Total	**(3.007)**	**(3.317)**	**(1.488)**	**0.663**	**(1.281)**	**(8.430)**

5.4. Distribution Licence Fee

Reference	
Proposal Section	21.5
SEM Category(s)	DA-1 Distribution licence fee
Regulatory Driver(s)	Base year adjustment
Forecast: 2015-2020 (June 15 $)	($5.3m)

Description of the Change
Under the South Australian Electricity Act 1996, SA Power Networks must hold a licence to operate the distribution network, and is charged an annual licence fee.

Costing Methodology/Build Up
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.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	-	-	-	-	-	-
Materials	-	-	-	-	-	-
Services	3.320	3.320	3.320	3.324	3.324	**16.608**
Total	**3.320**	**3.320**	**3.320**	**3.324**	**3.324**	**16.608**

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	-
Materials	-	-	-	-	-	-
Services	(1.063)	(1.063)	(1.063)	(1.063)	(1.063)	**(5.315)**
Total	**(1.063)**	**(1.063)**	**(1.063)**	**(1.063)**	**(1.063)**	**(5.315)**

Supporting Documentation/Evidence

- Attachment 21.21 – Government of South Australia: Revised Distribution Licence Fee July 2015 (Letter)

5.5. Demand Management Incentive Allowance

Reference	
Proposal Section	21.5
SEM Category(s)	DA-19 Demand Management Innovation Fund
Regulatory Driver(s)	Base year adjustment
Forecast: 2015-2020 (June 15 $)	($4.3m)

Description of the Change
The 2015-20 F&A provides for a Demand Management Incentive Allowance (**DMIA**) of $3.0 million to apply in the RCP. This allowance is for the development of initiatives to lower or shift peak demand.

Costing Methodology/Build Up
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 allowance.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	0.676	1.376	**2.052**
Materials	N/A	N/A	N/A	0.695	1.395	**2.090**
Services	N/A	N/A	N/A	0.062	0.409	**0.471**
Total	**N/A**	**N/A**	**N/A**	**1.433**	**3.180**	**4.613**

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	(0.431)	(0.431)	(0.431)	(0.431)	(0.431)	**(2.155)**
Materials	(0.430)	(0.430)	(0.430)	(0.430)	(0.430)	**(2.150)**
Services	-	-	-	-	-	**-**
Total	**(0.861)**	**(0.861)**	**(0.861)**	**(0.861)**	**(0.861)**	**(4.305)**

5.6. Non Network Solution

Reference	
Proposal Section	21.5
SEM Category(s)	DA-24 Non Network Solutions
Regulatory Driver(s)	Base year adjustment
Forecast: 2015-2020 (June 15 $)	$1.3m

Description of the Change

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.

Costing Methodology/Build Up

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 that the 2013/14 base year costs of $0.3 million.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	-	-	-
Materials	N/A	N/A	N/A	-	-	-
Services	N/A	N/A	N/A	0.335	0.435	**0.770**
Total	**N/A**	**N/A**	**N/A**	**0.335**	**0.435**	**0.770**

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	**-**
Materials	-	-	-	-	-	**-**
Services	0.155	0.207	0.258	0.310	0.362	**1.292**
Total	**0.155**	**0.207**	**0.258**	**0.310**	**0.362**	**1.292**

5.7. Property

Reference	
Proposal Section	21.5
SEM Category(s)	A-24 Real Estate - offices & depots
Regulatory Driver(s)	Base year adjustment
Forecast: 2015-2020 (June 15 $)	$2.1m

Description of the Change

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. A 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.

Costing Methodology/Build Up

An 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.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	N/A	N/A	N/A	-	-	**-**
Materials	N/A	N/A	N/A	-	-	**-**
Services	N/A	N/A	N/A	0.078	0.414	**0.492**
Total	**N/A**	**N/A**	**N/A**	**0.078**	**0.414**	**0.492**

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	-	-	-	-	-	-
Materials	-	-	-	-	-	-
Services	0.414	0.414	0.414	0.414	0.414	**2.070**
Total	**0.414**	**0.414**	**0.414**	**0.414**	**0.414**	**2.070**

5.8. Finance Adjustments

Reference	
Proposal Section	21.5
SEM Category(s)	A-16 Finance adjustments
Regulatory Driver(s)	Base year adjustment
Forecast: 2015-2020 (June 15 $)	$7.1m

Description of the Change
One-off accounting adjustments relating to provision changes such as long service leave and annual leave have been included in the regulatory accounts. We have forecast the real cash operating expenditures associated with such transactions.

Costing Methodology/Build Up
We have adjusted the base year to offset the negative 2013/14 base year amount of $1.4 million (June 2015 $) to ensure that the net forecast expenditure in this cost category for the 2015-20 RCP is zero.

Current RCP (2010/11 to 2014/15)

2010-15 RCP ($m, nominal)	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Forecast 2014/15	Forecast 2010-15
Labour	0.603	6.354	(3.299)	(1.372)	-	**2.286**
Materials	-	-	-	-	-	**-**
Services	-	-	-	-	-	**-**
Total	**0.603**	**6.354**	**(3.299)**	**(1.372)**	**-**	**2.286**

Next RCP (2015/16 to 2019/20)

2015-20 RCP June 2015 ($m)	Forecast 2015/16	Forecast 2016/17	Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	Forecast 2015-20
Labour	1.417	1.417	1.417	1.417	1.417	**7.085**
Materials	-	-	-	-	-	**-**
Services	-	-	-	-	-	**-**
Total	**1.417**	**1.417**	**1.417**	**1.417**	**1.417**	**7.085**