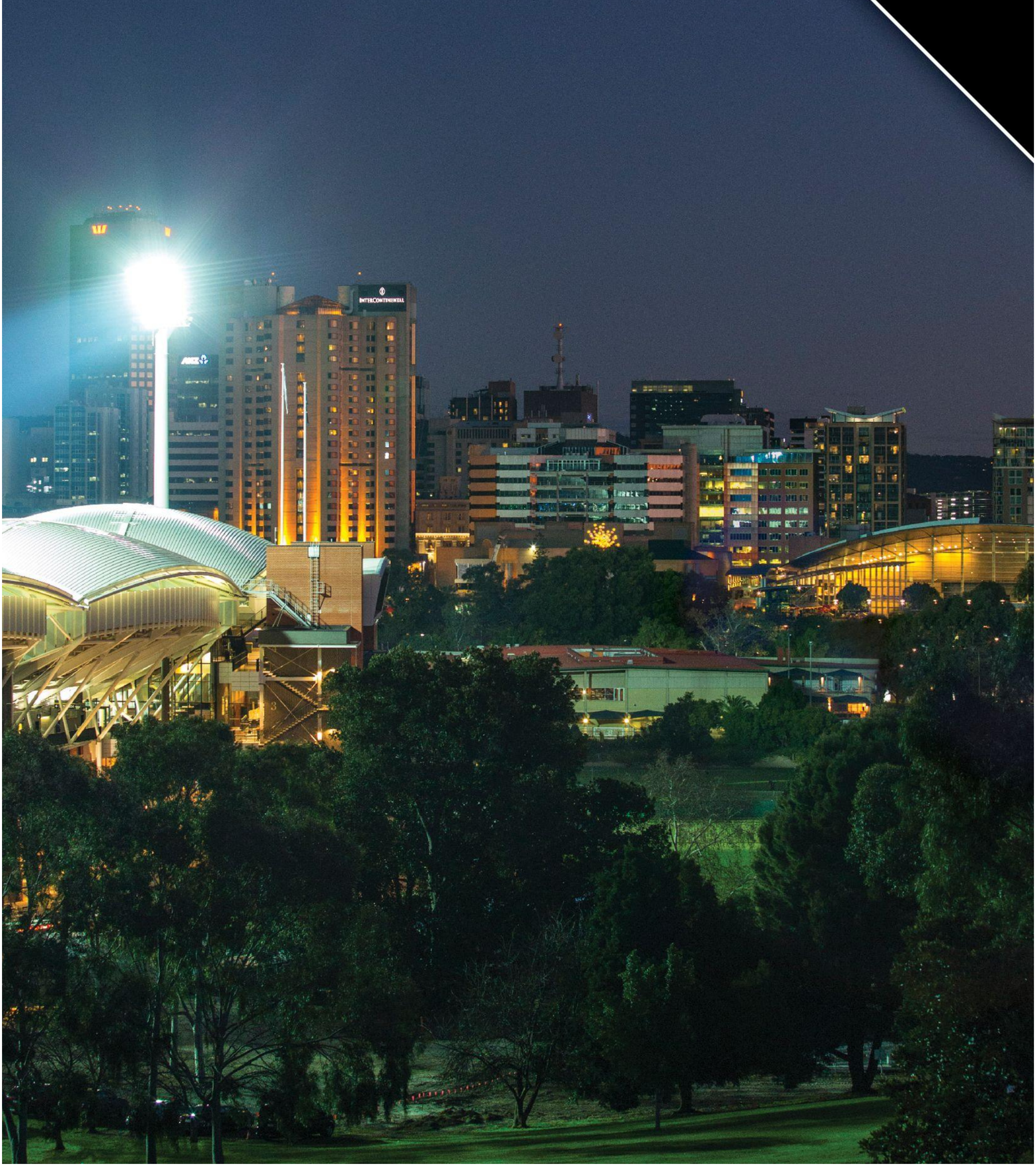
Attachment G.5

SAPN_Protection Compliance_Backup protection

03 July, 2015



Contents

1. EXECUTIVE SUMMARY

This document describes the requirement on SA Power Networks to provide 'backup' protection systems in rural areas in order to comply with National Electricity Rules (**NER**) and SA Power Networks' Network Directive (**ND J1**) – Distribution Protection Philosophy.

Secondary or 'backup' protection is designed to operate when a power system fault is not cleared in the required time because of the failure or inability of a primary protection device to operate. Adequate backup protection is defined as being able to detect any credible fault on a high voltage (**HV**) feeder[1] and clear the fault within an acceptable time frame, should any one protection device or fault breaking device fail.

Clause S5.1.9(c) of the NER provides that:

> *"Subject to clauses S5.1.9(k) and S5.1.9(l), a Network Service Provider must provide sufficient primary protection systems and back-up protection systems (including breaker fail protection systems) to ensure that a fault of any fault type anywhere on its transmission system or distribution system is automatically disconnected in accordance with clause S5.1.9(e) or clause S5.1.9(f)".*

NDJ1 reflects this obligation and is similar to the practices adopted by DNSPs in Victoria, Queensland, New South Wales and Western Australia. It follows that the practices reflected in NDJ1 represent standard industry practice or 'good electricity industry practice.

Importantly, compliance with the NER is mandatory and therefore this expenditure is required in order to achieve the capital expenditure objectives.

Adequate backup protection generally exists in the metropolitan region but is deficient in many rural areas due to the inherent design of rural networks. SA Power Networks' Backup Protection Project is designed to mitigate this risk in rural areas over a 12 year period. 12 years is considered a realistic time frame, balancing the risks with the costs involved. Field implementation of this project commenced in 2014. SA Power Networks is committed to reducing the safety risks associated with the failure of primary protection equipment and to meet the back up protection compliance requirement as stated above.

[1] HV feeders include 11kV feeders and 19kV single wire earth return (**SWER**) feeders.

2. REGULATORY DRIVERS

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

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

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

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

SA Power Networks is also required, under the conditions of its Distribution Licence and section 25 of the *Electricity Act 1996* (SA) (**Electricity Act**), to comply with its ESCoSA approved SRMTMP. Section 2.3.3 of the SRMTMP provides that we must comply with ND J1 which addresses certain safety and technical matters.

It is SA Power Networks' duty to take reasonable steps to ensure that our distribution system is safe and safely operated (in accordance with section 60(1) of the Electricity Act) and to maintain and operate our facilities in accordance with good electricity industry practice (in accordance with clause 5.2.1(a) of the NER). These duties require us to have regard to applicable standards of safety to ensure that the distribution system is safe and safely operated and is maintained and operated in a manner that is consistent with the degree of skill, diligence, prudence and foresight expected from Australian electricity distribution system operators.

SA Power Networks' activities are also governed by the *Work Health and Safety Act 2012* (SA) (**WHS Act**) and SA Power Networks owes a non-delegable duty (in respect of health and safety to both its workers and all other persons who may be affected by assets within its management) to, <u>so far as is reasonably practicable</u>, ensure that its workplace is without risk to the health and safety of any person. In the context of dangers caused by its distribution system, SA Power Networks has a duty towards all 'other persons' in the vicinity of its distribution system under the WHS Act.

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

It is for this reason that the definition of 'reasonably practicable' in section 18 of the WHS Act provides that the cost of taking a control measure must be 'grossly disproportionate' to the risk it seeks to address before it will not be reasonably practicable to take that measure.

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

3. BACKUP PROTECTION PROJECT

3.1 Scope

The Backup Protection Project scope includes reviewing the compliance of existing rural protection systems on 11kV and 19kV feeders and applying the most cost-effective solution to mitigate any risks identified.

3.2 Purpose

The purpose of the Backup Protection Project is to implement efficient and effective solutions to achieve adequate primary and backup protection in order to comply with the NER and SA Power Networks' Network Directives requirement.

4. BACKGROUND

Historically, SA Power Networks has relied upon fuses and hydraulic (mechanical) reclosers as primary protection devices for rural feeders and these devices have been very reliable. However, hydraulic reclosers are not 'fail-safe' and these assets are ageing and now failing to operate correctly. Consequently, SA Power Networks is experiencing safety issues associated with these assets failing.

Protection devices such as fuses, reclosers and circuit breakers are designed to only operate in very short time frames under high (fault) current conditions. Locations that have inadequate backup protection are mostly in our 19kV SWER system located in remote areas where transformers are only protected by fuses on the HV side. Long rural feeders typically have high electrical impedance which can result in relatively low current levels under certain fault conditions. In these situations, primary protection devices may not operate for several seconds, or not at all.

Where the primary protection device (fuse/recloser) does not operate, the faulted location can remain live until another network asset, typically the supply transformer, fails. When this occurs, a protection device further upstream in the network will operate. The introduction of an electronic recloser at or near the existing fuse/hydraulic recloser location will ensure better primary protection operation and also enable supervisory control and data acquisition (**SCADA**) monitoring and allow a faster response if the fault has not cleared.

5. RISKS

A large portion of our rural HV network has been assessed as having inadequate primary and backup protection. SA Power Networks is concerned with the safety risks related to failure of the primary protection devices, based on recent history of transformer and recloser failures.

These risks are not prevalent in the metropolitan area where, generally, adequate backup protection exists in the event of a primary protection device failure. They are prevalent in rural and remote areas, often on 19kV SWER feeders, which rely on HV fuses on the supply side of the SWER isolating transformer.

Inadequate backup protection can lead to the following consequences:

- live poles (SA Power Networks uses Stobie poles containing steel). The safety of public and animals in rural areas are put at risk if they come in contact with a live pole;
- burn down of conductors and supply transformers (asset failure); and
- risk of fire start (ignition can occur from sparks/molten aluminium arising from asset failure.

Based on a protection review done in 2013, SA Power Networks estimated there are currently 362 11kV and 19kV feeders requiring protection upgrades. The majority of the feeders are located in bush fire risk areas (**BFRAs**). We commenced implementation of the Backup Protection Project in 2014, targeting feeders that carry the highest risk.

Table 1 sets out our estimates of the feeders that are currently at risk of failure.

Table 1: Estimated feeders at risk

Estimated Feeders at Risk in Network (Without Adequate Backup Protection)	11kV Feeders		19kV Feeders	Total Number at Risk
	From Substation	From 33kV Line via 33/11kV Transformers		
Number of affected feeders in HBFRA*	8	15	60	83
Length of affected feeders in HBFRA (km)	270	251	2,073	2,594
Number of affected customers in HBFRA	3,823	2,386	4,263	10,472
Number of affected feeders in MBFRA*	26	17	231	274
Length of affected feeders in MBFRA (km)	601	89	16,303	16,993

Estimated Feeders at Risk in Network (Without Adequate Backup Protection)	11kV Feeders		19kV Feeders	Total Number at Risk
	From Substation	From 33kV Line via 33/11kV Transformers		
Number of affected customers in MBFRA	10,007	1,093	16,858	27,958
Number of affected feeders in NBFRA*	0	0	5	5
Length of affected feeders in NBFRA (km)	0	0	182	182
Number of affected customers in NBFRA	0	0	261	261
Total number of affected feeders	34	32	296	**362**
Total length of affected feeders (km)	871	340	18,558	**19,769**
Total number of affected customers	13,830	3,479	21,382	**38,691**

HBFRA = High Bush Fire Risk Area
MBFRA = Medium Bush Fire Risk Area
NBFRA = Non Bush Fire Risk Area

6. EVIDENCE OF INCREASING FAILURE RATES

6.1 Recloser Failure Rates

In the 18 months from August 2013 to January 2015, SA Power Networks replaced 27 faulty 11kV reclosers and 19 faulty 19kV reclosers. These high failure rates prompted SA Power Networks to take steps to ensure all protection devices in our network are backed up by a secondary protection device in case the primary protection device fails.

Table 2: Reclosers replaced / repaired from August 2013 – January 2015

Type of recloser	2013 (5 months)	2014 (12 months)	2015 (1 month)	Total Failure (18 months)	Average Failure per month
11kV Recloser	2	24	1	27	1.5
19kV Recloser	9	10	0	19	1.1
Total	**11**	**34**	**1**	**46**	**2.6**

6.2 Protection Failure Rates

In the past ten years there have been 22 High Voltage (**HV**) faults where primary protection has failed. Of these failures, eight had inadequate back-up protection resulting in significant consequences. Several examples of these failures, and the resulting consequences, are outlined below.

In 2009, near Millicent in the south-east of South Australia, one 2.5MVA transformer failed following the failure of a feeder exit recloser to operate for a downstream fault. Without sufficient backup protection, the fault was only detected and cleared once the transformer had failed catastrophically.

On 30 March 2013, a contractor’s heavy equipment brought down a conductor on the 19kV feeder in the Naracoorte (south-east) region. The upstream mechanical recloser failed to operate. The isolating transformer’s primary fuses operated but the fault was not cleared within a reasonable timeframe and caused catastrophic failure to the isolating transformer.

On 3 October 2014, a distribution transformer supplied from a 19kV feeder in the Yorketown (Yorke Peninsula) region failed. The feeder exit recloser failed to clear the fault. A larger fault current subsequently developed inside the isolating transformer until the fuses on the supply side of the transformer operated. The inability of the recloser to clear the fault caused a fire to start in the area, and failure of the isolating transformer.

7. STRATEGY

7.1 Strategy outline

The implementation strategy to improve backup protection is based on the following actions:

- Review all 11kV and 19kV feeders within rural and remote areas to assess the existing backup protection. This excludes any feeders that are part of large capital projects or customer projects where the backup protection inadequacy will be addressed in the projects' scopes.
- For feeders with poor or no backup protection, we propose the following solutions:
  - Install 33kV electronic reclosers with sensitive neutral overcurrent (**SNO**) relays on the primary side of 33/11kV transformers to improve backup protection for 11kV feeders;
  - Install 19kV electronic reclosers and reconfigure existing mechanical reclosers to provide adequate backup protection for 19kV feeders; and
  - Adjust existing protection settings and/or install fuses on minor sections of power lines where customer reliability is not greatly impacted to achieve backup protection in all feeders.

The strategies are discussed in sections 7.2 and 7.3 below and are in line with good electricity industry practice and considered the most prudent remediation solutions.

7.2 11kV Feeders

The 11kV feeders in our rural network are typically supplied from:

- a 33/11kV transformer within a zone substation; or
- a 33/11kV transformer situated on a 33kV sub-transmission line.

All 33/11kV transformers are normally protected by 33kV fuses. The 11kV feeders emanating from a zone substation are protected by a single feeder exit recloser. Due to the inherent nature of fuse characteristics, fuses do not provide adequate backup protection for faults occurring near the end of the 11kV feeder.

The current day method to provide backup protection for faults occurring near the end of an 11kV feeder is to replace the 33kV transformer fuses with 33kV electronic reclosers and SNO relays[2]. The replacement of 33kV fuses with electronic reclosers provides a safer backup protection for the 11kV feeders and is aligned with good electricity industry practice.

[2] The SNO relay is an additional relay fitted to the recloser to aid in the detection of long distance faults.

The SNO protection relay will detect low sensitive earth fault currents which typically occur when a conductor is down, reducing the risk of an electric shock or a fire start. To enable remote monitoring these protection devices are connected to SCADA.

7.3 19kV Feeders

The 19kV SWER feeders in our network are supplied from:

- one phase of a 33kV feeder; or
- one phase of an 11kV feeder via a SWER isolating transformer.

94% of our 448 19kV SWER feeders are protected by mechanical 'E-type' reclosers with liquid fuses on the primary (high) side of the isolating transformer. Often these fuses are slow to operate when the mechanical recloser fails to operate due to low fault current levels, especially on longer feeders.

We propose the installation of new 19kV electronic reclosers as the primary protection device with the existing mechanical recloser used as a backup protection device. The mechanical reclosers will be set to '1 trip to lock out' and only operate if the primary electronic recloser fails to clear faults. During high bush fire risk days, the electronic reclosers will be remotely set via SCADA. This aligns with our network practice and 'good electricity industry practice' in Australia.

8. OPTIONS ANALYSIS

Various options have been considered to improve backup protection on rural feeders. These options are presented below. Option 2 is the most efficient and prudent solution to appropriately manage the risk.

8.1 Option 1 – Do Nothing (Not Acceptable)

Doing nothing is not acceptable as SA Power Networks has a regulatory obligation to comply with the NER and ND J1, the Electricity Act and the WHS Act, and SA Power Networks' current practices in relation to backup protection will not satisfy these obligations during the 2015-20 RCP. The do nothing option is assessed as **HIGH** risk (**POSSIBLE** likelihood and **MAJOR** consequence).

The cost for this option is $0.

Table 3: Option 1

Pros	Cons
Nil capital expenditure.	Safety of public is put at risk in case of primary protection failure. The conductors at the faulty location will remain live and the exposure of public to the risk is greatly increased without backup protection to act accordingly. Plant damage due to slow or non-existent backup protection if the primary protection device fails to operate for a legitimate fault. Failures of the primary protection equipment will lead to fire start or faulty energised assets when the fault energy is not immediately removed by the protection device.

8.2 Option 2 – Protection solutions outlined in section 7. (Preferred Option)

In option 2, SA Power Networks is proposing to apply solutions as per the strategy described in section 7 above, including to:

- install 33kV electronic reclosers with SNO relays and SCADA connectivity to replace existing 33kV fuses to provide backup protection for 11kV feeders;
- install 19kV electronic reclosers with SCADA connectivity to provide primary protection and reconfigure existing 19kV mechanical reclosers as the backup protection for 19kV feeders; and

- on a case by case basis, change existing protection settings and/or install additional sectionalising fuses after careful assessment.

The ultimate solutions selected will be determined by the lowest cost solution that adequately resolves backup protection gaps within existing reliability standards. The estimated cost for this option is $39.6 (June 2015, $ million) over 12 years (from 2014 to 2025). For the 2015-20 RCP, the estimated cost is $18.6 (June 2015, $ million).

Table 4: Option 2

Pros	Cons
The failure of the protection equipment can be remotely monitored to some degree and acted on immediately to reduce customer and community safety risks. The damage of the plant can be significantly reduced by faster clearing times in the case of primary device failure. The fire start risk is mitigated by remotely setting SCADA connected reclosers to ‘1 trip to lock out’ during high fire danger level (**FDL**) days. This will avoid sending crews into high bushfire risk regions during critical days to manually switch the device into single trip.	Capital cost $39.6 million over 12 years.

8.3 Option 3 –All Electronic Reclosers on SWERs (Not Recommended)

Compared to Option 2 above, instead of reconfiguring existing 19kV mechanical reclosers to achieve full back-up protection, Option 3 replaces existing mechanical reclosers with electronic reclosers to act as backup reclosers. This means each feeder will have two electronic reclosers instead of one electronic recloser and one mechanical recloser for primary and backup protection. This option provides the same backup protection and clearing times as Option 2 but at a higher cost.

The estimated cost for this option is $52.2 (June 2015, $ million) over the planned 12 year period (from 2014 to 2025), which is $12.6 million more than Option 2 over that 12 year period.

Table 5: Option 3

Pros	Cons
Backup protection can be achieved but at significant cost.	The cost is higher ($52.2 million compared to $39.6 million) while achieving same backup protection effect as Option 2.

9. PROJECT SCHEDULE

The Backup Protection Project is a 12 year project that commenced in 2014 and is expected to be completed in 2025 to overcome all the backup protection issues of the 11kV and 19kV feeders in our network.

In 2014, SA Power Networks replaced 33kV fuses at 2 substations with 33kV electronic reclosers and installed SNO relays to provide full backup protection to 11kV feeders. In addition, 5 electronic reclosers were installed to overcome backup protection issues on 11kV and 19kV feeders. All electronic reclosers are connected to SCADA to allow for remote monitoring and switching control.

In 2015, SA Power Networks plans to replace three 33kV fuses with 33kV reclosers and SNO relays to overcome backup protection issues on 11kV feeders, and install 5 electronic reclosers on 19kV feeders. The schedule for the Backup Protection Project implementation is in Attachment 1 to this document.

10. PROJECT COST

10.1 Expenditure History

SA Power Networks started the Backup Protection Project in 2014. Expenditure was $1.1 (2014 $ million) in 2014 and is forecast to be $1.6 (June 2015, $ million) in 2015.

10.2 Unit Costs

As explained in section 7, we propose to replace 33kV fuses with electronic reclosers to address problems on 11kV feeders and install additional electronic reclosers on 19kV feeders. However, on a case by case basis, full feeder backup protection can occasionally be achieved by changing existing protection settings and/or installing sectionalising fuses as more efficient solutions. The unit cost for each solution is stated in the table below.

Table 6: Unit cost per solution (based on historic Network Management costs)

Solutions Type	Unit Cost
Substation 33kV Reclosers	$ 452,100
Line 33kV Reclosers	$ 286,000
19kV Feeders reclosers	$ 73,150
Others (settings change, sectionalising fuses)	$ 15,000

10.3 Total Project Cost

The total cost to provide complete backup protection on our 11kV and 19kV feeders is estimated at $39.6 (June 2015, $ million) over 12 years. The cost for the 2015-20 RCP is $18.6 (June 2015, $ million), refer Table 7. The detailed cost breakdown[3] is in Attachment 1 to this document.

Table 7: SA Power Networks' forecast back-up protection capital expenditure for the 2015-20 RCP (June 2015, $ million)

Safety	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Back-up protection	2.8	3.0	3.4	3.6	5.8	18.6

[3] Note Attachment 1 cost breakdown is in Network Management $ per calendar year.

ATTACHMENT 1 – Backup Protection Project – Schedule and Cost breakdown

Note: Network Management $ thousand per calendar year

Solutions Type	Targeted Feeders	Year		2015-2020 RESET					2020-2025 RESET					Total
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
		year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10	year 11	year 12	
Substation 33kV Reclosers + relay	11kV	2	2	2	2	2	2	2	2	2	1	0	0	19
Line 33kV Reclosers + relay	11kV	1	1	2	2	3	3	4	4	5	6	6	4	41
19kV Feeders reclosers	19kV	4	5	18	25	25	25	24	24	22	20	24	10	226
Others (settings change, sectionalising fuses)	11kV and 19kV	0	0	0	0	0	0	1	1	1	1	1	0	5
Cost per year ('000)		**$1,028**	**$1,500**	**$2,793**	**$3,305**	**$3,591**	**$3,591**	**$3,828**	**$3,828**	**$3,969**	**$3,656**	**$3,498**	**$1,876**	**$36,462**