Rapid Earth Fault Current Limiter (REFCL) - 22kV Feeders Fuse Savers Program

Regulatory Investment Test for Distribution

Final Project Assessment Report

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Contents

Executive summary

AusNet Services is installing Rapid Earth Fault Current Limiters (REFCL) technology to achieve bushfire mitigation benefits to Victoria and our customers. Significant work is required at each zone substation to accommodate the installation of the REFCL equipment.

The existing fleet of fuse savers was installed in the distribution network eight to ten years ago. The continued use of the existing technology means that the tripping of a single phase due to faults can cause an imbalance in the network that triggers the REFCL to trip the entire feeder. As a consequence, customers will experience a deterioration in reliability as a result of REFCL installation if the existing fuse savers remain in operation.

AusNet Services is therefore proposing remedial network investment to avoid the adverse reliability impacts arising from the existing fuse savers for Tranche 1 and 2 of the REFCL installation program. For Tranche 3 of the REFCL program, the resolution of the fuse saver issues will be addressed as part of the REFCL installation program.

The total program of work is expected to be approximately $11.1 million, and therefore will be subject to the Regulatory Investment Test for distribution (RIT-D) in accordance with the National Electricity Rules (NER). This document is our Final Project Assessment Report, which demonstrates that our preferred option maximises the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market, in accordance with clause 5.17.1(b) of the NER.

In preparing this report, we considered alternative network solutions after concluding that there are no non-network options available to address the identified need. Following this analysis, we concluded that there were three potential options:

1. Business as Usual (counterfactual);
2. Installation of new generation fuse savers and Automatic Circuit Reclosers (ACRs); and
3. As per option 2, but using ACRs or S&C intellirupters rather than fuse savers.

In relation to Option 3, we found that ACRs or S&C intellirupters were more costly, without providing any material offsetting benefits. We therefore concluded that this option was not credible and it was not considered further.

Our net present value analysis shows that the second option delivers a substantial net benefit as shown in the table below.

Table 1: Net present value analysis ($'000, present value, nominal)

	Capex	Opex	Total direct costs	Risk cost (reliability)	Total cost
Option 1 – Business as Usual (counterfactual)	0.0	6,092	**6,092**	27,956	**34,048**
Option 2 – Installation of new generation fuse savers and ACRs	10,104	3,424	**13,529**	5,157	**18,685**

Note: Total may not add due to rounding.

The analysis shows that the total costs for Option 2 is $18.7 million compared to $34.0 million for the Business as Usual option, expressed in present value terms. The net present value analysis therefore shows that Option 2 provides a net economic benefit of $15.4 million, which is the difference between the total costs for Option 1 and Option 2 in present value terms. This is a significant net economic benefit given that the capital cost for Option 2 is expected to be $10.1 million.

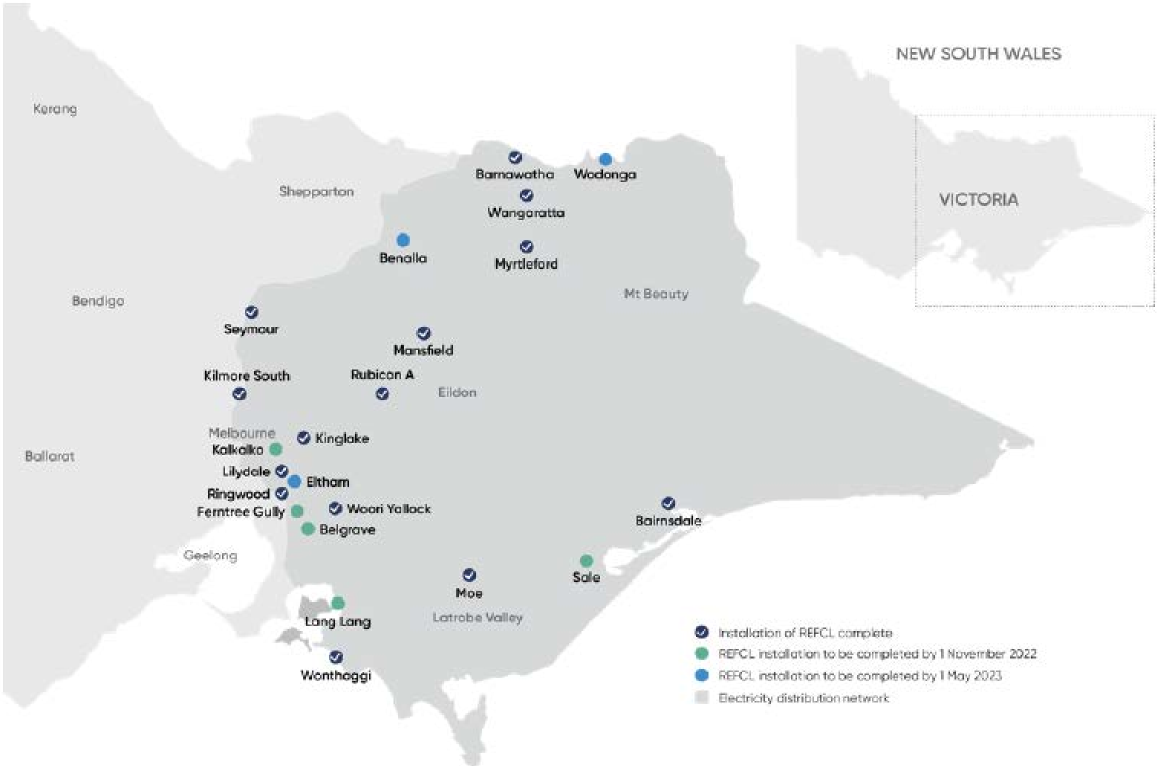
Accordingly, AusNet Services has concluded that Option 2 is the preferred option and should proceed in accordance with the timeframes specified in this report.

1 Introduction

The installation of REFCL technology is delivering bushfire mitigation benefits to Victoria and our customers. The REFCL program was established in response to Regulations[1] designed to reduce the likelihood of fires being initiated by electricity distribution network assets. The program is a world first in using REFCL technology to mitigate bushfire risk.

AusNet Services' REFCL program is being deployed in three tranches based on a points system that, by assigning more points to higher risk areas, aims to prioritise zone substations where fire mitigation measures would provide the greatest benefit. Figure 1 shows the progress that we have made in complying with the Regulations, with the final Tranche of the installation program to be completed by 1 May 2023.

Figure 1 –REFCL installation program



Significant work is required at each zone substation to accommodate the installation of the REFCL equipment. For example, the speed and sensitivity at which the REFCLs operate means traditional protection schemes distributed along a feeder will not operate as they normally would, to detect and isolate a faulted section of the network.

The existing fleet of fuse savers was installed in the distribution network eight to ten years ago. These fuse savers have limited capabilities for gang operation due to very slow communication with the other two phases. The continued use of the existing technology means that the tripping of a single phase due to faults can cause an imbalance in the network that triggers the REFCL to trip the entire feeder. As a consequence, customers will experience a deterioration in reliability as a result of REFCL installation if the existing fuse savers remain in operation.

AusNet Services is therefore proposing remedial network investment to avoid the adverse reliability impacts arising from the existing fuse savers for Tranche 1 and 2 of the REFCL installation program. For Tranche 3, the resolution of the fuse saver issues will be addressed as part of the REFCL installation program.

[1] Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016 (Amended Bushfire Mitigation Regulations).

The proposed works for the REFCL 22kV Fuse Savers Program relate to the feeders served by the following 13 zone substations, where the reliability issues are most significant:

Tranche 1

- Kilmore South;
- Seymour
- Wonthaggi;
- Wangaratta;
- Woori Yallock;

Tranche 2

- Eltham;
- Ferntree Gully;
- Bairnsdale;
- Lilydale;
- Moe;
- Wodonga Terminal Station;
- Belgrave; and
- Mansfield[2].

The total program of work is expected to be approximately $11.1 million, and therefore will be subject to the RIT-D in accordance with the NER. This document is our Final Project Assessment Report, which demonstrates that our preferred option maximises the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market, in accordance with clause 5.17.1(b) of the NER.

As the project cost is expected to be less than $12 million, we were not required to publish a Draft Project Assessment Report.[3] In January 2022, we published a notice explaining why there are no credible non-network options in relation to the REFCL 22kV Feeders Fuse Savers Program.[4] Accordingly, the NER does not require us to publish a non-network options report.[5]

2 Mansfield was part of T3 REFCL that was brought forward to T2.

3 Clause 5.17.4(n).

4 Clause 5.17.4(d).

5 Clause 5.17.4(c).

2 Identified need

AusNet Services' distribution network operates in a geographical location exposed to extreme bushfire risk, warranting significant investment to reduce the risk of electricity assets causing a bushfire.

The Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016 came into effect on 1 May 2016, amending the Electricity Safety (Bushfire Mitigation) Regulations 2013 (the Regulations). Among other obligations, the effect of the amendment requires AusNet Services to install REFCL technology at twenty-two specified zone substations and meet specific REFCL performance requirements (the Required Capacity) designed to reduce the fire start potential of electricity distribution assets.

Fuse savers are designed to prevent transient faults on a spur circuit resulting in sustained outages under conditions of medium or low current faults. The existing fuse savers were introduced and have been installed in the distribution network over the last eight to ten years. However, they are not suitable with REFCL technology due to slow communication between the other two phases, leading to very slow gang operation which can create imbalance in circuits to trigger the tripping of the entire feeder by the Ground Fault Neutraliser (GFN) – an important component of REFCL technology.

Unless remedial action is taken, adverse customer reliability will result from the continued operation of existing fuse savers on feeders served by Tranche 1 and Tranche 2 zone substations. In particular, our analysis shows that the financial penalties resulting from the Service Target Performance Incentive Scheme (STPIS) of approximately $11 million per annum at the relevant zone substations is at least partially attributable to the impact of existing fuse savers. The reliability impact for our customers is therefore significant.

The identified need, therefore, is to address the adverse reliability impacts that result from the continued use of existing fuse savers for REFCL protected zone substations completed in Tranche 1 and 2 of the installation program.

3 Assumptions underpinning the identified need

The purpose of this chapter is to summarise the key input assumptions that underpin the identified need described in the previous chapter.

3.1 Regulatory Obligations

In addressing the identified need, we must satisfy our regulatory obligations, which we summarise below.

Clause 6.5.7 of the National Electricity Rules requires AusNet Services to only propose capital expenditure required in order to achieve each of the following:

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services, and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

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

Section 98(a) of the Electricity Safety Act requires AusNet Services to:

design, construct, operate, maintain and decommission its supply network to minimise as far as practicable –

(a) the hazards and risks to the safety of any person arising from the supply network; and

(b) the hazards and risks of damage to the property of any person arising from the supply network; and

(c) the bushfire danger arising from the supply network.

The Electricity Safety act defines 'practicable' to mean having regard to –

(a) severity of the hazard or risk in question; and

(b) state of knowledge about the hazard or risk and any ways of removing or mitigating the hazard or risk; and

(c) availability and suitability of ways to remove or mitigate the hazard or risk; and

(d) cost of removing or mitigating the hazard or risk.

Clause 3.1 of the Electricity Distribution Code requires AusNet Services to:

(b) develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution system assets and plans for the establishment and augmentation of transmission connections:

(i) to comply with the laws and other performance obligations which apply to the provision of distribution services including those contained in this Code;

(ii) to minimise the risks associated with the failure or reduced performance of assets; and

(iii) in a way which minimises costs to customers taking into account distribution losses.

Under clause 5.2 of the Electricity Distribution Code, AusNet Services:

> *must use best endeavours to meet targets required by the Price Determination and targets published under clause 5.1 and otherwise meet reasonable customer expectations of reliability of supply.*

3.2 Reliability issues and supporting data

The installation of REFCLs at designated zone substations is mandated by the Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016. As explained in the Executive summary, customers will experience a deterioration in reliability as a result of REFCL installation if the existing fuse savers remain in operation.

The reliability cost associated with 'business as usual' operation has been assessed based on STPIS impact of each feeder tripping using the 'Standard AusNet Service STPIS Calculator' for a 100 minute outage. The cost has been estimated based on average 50% STPIS impact on each feeder ($52k) tripping/outage with one incident per feeder per year. The latest estimated value of customer reliability is reflected in this calculation.

The identified need has focused on the 13 zone substations where the reliability issues are considered to be most significant. The key assumptions for the Tranche 1 and 2 zone substations are set out below.

Tranche 1 – Key assumptions

Relevant zone substations:

- Kilmore South (KMS);
- Seymour (SMR)
- Wonthaggi (WGI);
- Wangaratta (WN); and
- Woori Yallock (WYK).

Total number of customers affected is 65,808 on 22 feeders.

Tranche 2 – Assumptions

Relevant zone substations:

- Eltham (ELM);
- Ferntree Gully (FGY);
- Bairnsdale (BDL);
- Lilydale (LDL);
- Moe (MOE);
- Wodonga Terminal Station (WOTS);
- Belgrave (BGE); and
- Mansfield (MSD).

Total number of customers affected is 146,623 on 57 feeders.

3.3 Availability of technical solutions

An implicit assumption in our identified need is that there is technical solution to the identified need. AusNet Services considers that Siemens 3AD8 modules provide the next generation of fuse savers that are able to operate in conjunction with REFCL protected zone substations. In addition, the installation of ACRs provide an alternative where these fuse savers either not cost effective or cannot be deployed. The technical characteristics of the required works is discussed later in this FPAR.

4 Options considered

This section outlines the potential options that were considered to address the identified need. We identified three potential options:

1. Business as Usual (counterfactual);
2. Installation of new generation fuse savers and Automatic Circuit Reclosers (ACRs); and
3. As per option 2, but using ACRs or S&C intellirupters rather than fuse savers.

In relation to non-network options, we concluded that these were not feasible because:

- The reliability issues identified from the incompatibility of the existing fuse savers with REFCL operation can only be addressed through network investment, given the numbers of customers affected and the large number of tee-offs.
- While network balancing issues may be addressed by providing customers with batteries and solar pvs, these solutions are impractical given the radial feeder configuration (large number of tee-offs) and conductor annealing problem which require fuse protection.
- As the proposed capital works address the impact of REFCL operation on our distribution network and its service performance, non-network solutions cannot provide an effective substitute for the proposed capital works.
- The AER accepted our proposed inclusion of fuse savers in our contingent project application for Tranche 3 of the REFCL program, which reinforces our view that there are no non-network solutions available.[6]

4.1 Option 1: Business as Usual

The Business as Usual (counterfactual) option would not involve undertaking any investment, outside of the normal operational and maintenance processes. Under this option, we would continue the use of the existing fuse savers in service with REFCL technology. As already explained, this would lead to poorer reliability outcomes compared to the period prior to the installation of REFCLs.

4.2 Option 2: Installation of fuse savers and ACRs

This option involves installation of new generation fuse savers, ACRs and other minor works. This option would ensure the proper operation of REFCL technology on these relevant feeders in coordination with new generation fuse savers. As a consequence, this option would improve reliability performance compared to the Business as Usual option, avoid significant STPIS penalties and deliver better outcomes for our customers.

In relation to Tranche 1 zone substations, this option would involve the following works:

- Install new generation fuse savers, Siemens 3AD8 modules, at 80 switch locations including the replacement of old fuse savers;
- Install 12 ACRs (Noja RC10 or RC20);
- Install three gas switches;
- Reconductor five spans;
- Remove fuses at 80 poles; and
- Other minor works to facilitate the above works.

6 AER, Final Decision, Contingent Project Application, Installation of Rapid Earth Fault Current Limiters (REFCLs) – tranche three, 3 October 2019, page 46.

In relation to Tranche 2 zone substations, this option would involve the following works:

- Install 50 new generation fuse savers;
- Replace 4 old fuse savers with new generation fuse savers;
- Install 1 line ACR;
- Replace 43 existing fuse links with new solid links;
- Reconductor 4 sections; and
- Other minor works to facilitate the above works.

Installation work is scheduled to start in Feb 2023 with project completion is scheduled for March 2026.

The cost estimate has been developed based on previous ACR installation, fuse saver replacement, fuse solid link replacement and limited fuse upgrade projects will be completed prior to commencement of the implementation phase.

4.3 Option 3: As per option 2, but using ACRs or S&C intellirupters rather than fuse savers

In relation to Option 3, we found that this option provides the same reliability benefits, but required additional capital expenditure of $2.25 million in the case of ACRs and $8.2 million in relation to S&C intellirupters. While the use of ACRs or S&C intellirupters would provide some improvement in relation to the more efficient management of the network, this improvement cannot justify the additional capital expenditure associated with this option.

Accordingly, this option was not considered credible and is not considered further.

5 Economic assessment of the credible options

5.1 Market benefits

The regulatory investment test for distribution requires the RIT-D proponent to consider whether each credible option provides the classes of market benefits described in clause 5.17.1(c)(4) of the NER. To address this requirement, the table below discusses our approach to each of the market benefits listed in clause 5.17.1(c)(4) in assessing the credible options to address the identified need.

Table 2: Analysis of Market Benefits

Class of Market Benefit	Analysis
(i) changes in voluntary load curtailment;	The credible option is not expected to lead to changes in voluntary load curtailment.
(ii) changes in involuntary load shedding and customer interruptions caused by network outages, using a reasonable forecast of the value of electricity to customers;	The credible option is expected to have an impact on involuntary load shedding. This market benefit is quantified in section 5.4.
(iii) changes in costs for parties, other than the RIT-D proponent, due to differences in: *(A) the timing of new plant;* *(B) capital costs; and* *(C) the operating and maintenance costs;*	There is no impact on other parties.
(iv) differences in the timing of expenditure;	This project will not result in changes in the timing of other expenditure.
(v) changes in load transfer capacity and the capacity of Embedded Generators to take up load;	This project will not impact on the capacity of Embedded Generators to take up load.
(vi) any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the National Electricity Market;	This project will not impact the option value in respect to likely future investment needs of the NEM.
(vii) changes in electrical energy losses; and	This project will not result in changes to electrical energy losses.
(viii) any other class of market benefit determined to be relevant by the AER.	We do not consider any other class of market benefit as relevant to the selection of the preferred option.

5.2 Methodology

The purpose of this section is to provide a high level explanation of our methodology for identifying the preferred option. As a general principle, it is important that the methodology takes account of the identified need and the factors that are likely to influence the choice of the preferred option. As such, the methodology is not a 'one size fits all' approach, but one that is tailored for the particular circumstances under consideration.

The identified need for this project can be described in terms of supply risk, where an asset failure may lead to a loss of supply to customers.

In monetising supply risk, we adopt a probabilistic planning methodology which considers the likelihood and severity of critical network conditions and outages. The expected annual cost to customers associated with supply risk is calculated by multiplying the expected unserved energy (the expected energy not supplied based on the probability of the supply constraint occurring in a year) by the value of customer reliability (VCR).

The purpose of the cost benefit analysis that underpins the RIT-D assessment is to determine whether there is a cost effective option to mitigate the supply risk (or 'risk-cost'). In order to be cost effective, the reduction in the aggregate risk-cost that an option is expected to provide must exceed the cost of implementing that option. The preferred option provides greatest expected net benefit, expressed in present value terms.

In the absence of remedial action, Figure 2 shows how the risk-cost will typically increase as the risk of asset failure and energy at risk increase over time. The optimal timing of the preferred option occurs when the annualised capital cost of that option (or the operating cost for a non-network option) is equal to the risk-cost.

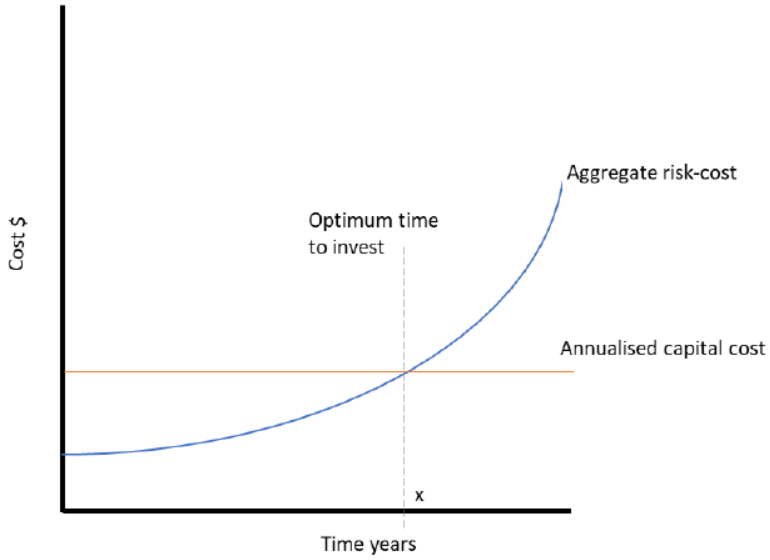


Figure 2: Increasing risk-cost over time and optimal project timing

In effect, the preferred option delivers the lowest total cost to customers, which is the sum of the cost of implementing that option and any residual risk-cost. The identification of the preferred option is complicated by the fact that the future is uncertain and that various input parameters are 'best estimates' rather than known values. As a consequence, the RIT-D analysis must be conducted in the face of uncertainty.

As recommended by the AER's application guidelines, we use sensitivity analysis to assist in determining an appropriate set of reasonable scenarios. In applying sensitivities and scenarios to our cost benefit assessment, we have regard to the particular circumstances to ensure that the approach is appropriate. Where our analysis shows that an option is clearly preferred, we will not undertake further testing. This approach is consistent with clause 5.17.1(c)(2) of the Rules, which states that the RIT–D must not require a level of analysis that is disproportionate to the scale and likely impact of each credible option considered.

In preparing the RIT-D, we have also had regard to AEMO's 2021 Inputs, Assumptions and Scenarios Report and its draft 2022 Integrated System Plan (ISP). We note that the scenarios adopted by AEMO are focused particularly on the matters that are relevant to major transmission investments, rather than distribution investments of the type considered in this report. Accordingly, we have adopted an approach that is appropriate to the particular circumstances described in this report relating to the identified need and the credible options.

5.3 Key variables and assumptions

The table below sets out the key variables and assumptions that have been applied in this FPAR.

Table 3: Key variables and assumptions

Variable / assumption	Approach adopted
Modelling Period	The expected life of the new assets in this RIT-D is 20 years. Accordingly the modelling period has been taken as 20 years.
Number of assets to be installed	Based on the high risk feeders from the relevant zone substations.
Network Impact Cost	Average network impact cost is based on tripping of the entire feeder due to old type fuse savers and REFCL installations and an average 50% of STPIS value. The STPIS value has been taken from 'Standard AusNet Service STPIS Calculator'.
Unplanned Opex Costs	Unplanned maintenance cost is based on the cost of feeder inspection and urgent switching and repair works.
Risks/Cost Savings	Progressive reduction (20%, 60% and 90%) in risks/costs have been estimated with completion of fuse replacement and other works in the first and second financial years. A residual risk of 10% has been assumed on completion of works due to unforeseen incorrect coordination of the REFCL and fuse savers.

The nature of the identified need is such that the variables typically used in the cost-benefit analysis, such as demand forecasts, are not a key driver of the investment decision.

5.4 Net present value analysis

The economic analysis presented below allows comparison of the economic costs and benefits of the credible option compared to the Business as Usual option. The table shows the total cost of each option, which includes capital expenditure, operating expenditure and the risk cost associated with reliability performance.

Table 4: Net present value analysis ($'000, present value, nominal)

	Capex	Opex	Total direct costs	Risk cost (reliability)	Total cost
Option 1 – Business as Usual (counterfactual)	0.0	6,092	**6,092**	27,956	**34,048**
Option 2 – Installation of new generation fuse savers and ACRs	10,104	3,424	**13,529**	5,157	**18,685**

Note: Total may not add due to rounding.

The analysis shows that the operating expenditure associated with Business as Usual is higher than the operating expenditure for Option 2, while the capital expenditure for Business as Usual is zero compared to Option 2 capital expenditure of $10.1 million in present value terms. The higher direct costs for Option 2 are more than offset by the lower risk cost, which is $5.16 million compared to $27.96 million for the Business as Usual option.

The analysis shows that the total costs for Option 2 is $18.7 million compared to $34.0 million for the Business as Usual option, expressed in present value terms. The net present value analysis therefore shows that Option 2 provides a net economic benefit of $15.4 million, which is the difference between the total costs for Option 1 and Option 2 in present value terms. This is a significant net economic benefit given that the capital cost for Option 2 is $10.1 million.

5.5 Scenario analysis and sensitivity testing

As noted in section 5.2, where our analysis shows that an option is clearly preferred, it is not necessary to undertake further testing through scenario analysis and sensitivity testing. This approach is consistent with clause 5.17.1(c)(2) of the Rules, which states that the RIT-D must not require a level of analysis that is disproportionate to the scale and likely impact of each credible option considered.

In relation to the cost benefit analysis presented in the previous section, we note that the significant benefits that Option 2 provides in relation to addressing the reliability issues associated with the existing fuse savers, as discussed in Chapter 2. This analysis, together with obligations under clause 5.2 of the Electricity Distribution Code, which requires us to use best endeavours to meet our customers' reasonable expectations of reliability of supply, we consider there to be an overwhelming case to proceed with Option 2.

We note that even if both the capital costs associated with Option 2 were double our forecast, Option 2 would remain preferable to the Business as Usual option. We also note that combining this higher capital expenditure with twice the risk-cost for Option 2, would produce a total cost for Option 2 of $33.9 million[7], which would still provide a modest net economic benefit for Option 2 of $0.1 million. On that basis, we do not consider it productive to undertake further sensitivity testing or scenario analysis.

5.6 Preferred option

The result of our cost benefit analysis is that Option 2 is the preferred option, which involves the following works:

1. At Kilmore South (KMS); Seymour (SMR) Wonthaggi (WGI); Wangaratta (WN); and Woori Yallock (WYK):
   - Install new generation fuse savers, Siemens 3AD8 modules, at 80 switch locations including the replacement of old fuse savers;
   - Install 12 ACRs (Noja RC10 or RC20);
   - Install three gas switches;
   - Reconductor five spans;
   - Remove fuses at 80 poles; and
   - Other minor works to facilitate the above works.
2. At Eltham (ELM); Ferntree Gully (FGY); Bairnsdale (BDL); Lilydale (LDL); Moe (MOE); Wodonga Terminal Station (WOTS); Belgrave (BGE); and Mansfield (MSD):
   - Install 50 new generation fuse savers;
   - Replace 4 old fuse savers with new generation fuse savers;
   - Install 1 line ACR;
   - Replace 43 existing fuse links with new solid links;
   - Reconductor 4 sections; and
   - Other minor works to facilitate the above works.

7 This is calculated by doubling the expected capital expenditure to $20.2 million, adding the estimated operating expenditure of $3.4 million and doubling the risk cost to $10.3 million.

6 Satisfaction of the RIT-D

In accordance with clause 5.17.4(j)(11)(iv) of the NER, we certify that the proposed option satisfies the Regulatory Investment Test for distribution. The table below shows how each of these requirements have been met by the relevant sections of this report.

It should be noted that the table below refers to the requirements for a draft (rather than final) project assessment report. The reason for this reference is that clause 5.17.4(r)(2) requires this report to provide the information in clause 5.17.4(j), as no Draft Project Assessment Report was prepared in relation to this project.

Table 5: Compliance with regulatory requirements

Requirement			Section
5.17.4(j) The draft project assessment report must include the following:			
(1)		a description of the identified need for the investment;	Section 2.
(2)		the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, reasons that the RIT-D proponent considers reliability corrective action is necessary);	Section 3.
(3)		if applicable, a summary of, and commentary on, the submissions on the non-network options report;	Not applicable.
(4)		a description of each credible option assessed;	Section 4.
(5)		where a Distribution Network Service Provider has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option;	Section 5.1, Table 1 and section 5.4.
(6)		a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;	Section 5.4.
(7)		a detailed description of the methodologies used in quantifying each class of cost and market benefit;	Section 5.2.
(8)		where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option;	Section 5.1.
(9)		the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	Section 5.4.
(10)		the identification of the proposed preferred option;	Section 5.6.
(11)		for the proposed preferred option, the RIT-D proponent must provide:	
	(i)	details of the technical characteristics;	Appendix.
	(ii)	the estimated construction timetable and commissioning date (where relevant);	Section 4.2.
	(iii)	the indicative capital and operating cost (where relevant);	Section 5.4.
	(iv)	a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution; and	Section 6, including this table.

Requirement		Section
	(v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent;	Not applicable.
	(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	Page 2.
5.17.4(k)	The RIT-D proponent must publish a request for submissions on the matters set out in the draft project assessment report, including the proposed preferred option, from: (1) Registered Participants, AEMO, non-network providers and interested parties; and (2) if the RIT-D proponent is a Distribution Network Service Provider, persons on its demand side engagement register.	Not applicable.
5.17.4(l)	If the proposed preferred option has the potential to, or is likely to, have an adverse impact on the quality of service experienced by consumers of electricity, including: (1) anticipated changes in voluntary load curtailment by consumers of electricity; or (2) anticipated changes in involuntary load shedding and customer interruptions caused by network outages, then the RIT-D proponent must consult directly with those affected customers in accordance with a process reasonably determined by the RIT-D proponent.	Not applicable.

Appendix – Technical characteristics

Technical risks

Survey and Detailed Design may be undertaken to confirm the quantities and effort involved in the scope, this may either reduce or increase the scope further which will impact the overall costs and project delivery dates.

Outages, generation and network support may be required for some of the works specified below which may increase the scope further which will impact the overall costs and project delivery dates, this is to be determined after survey and detailed design.

Outage availability may be constrained depending on the network and the time of year required, this will impact the overall project delivery and construction dates.

Any design, concept or standard changes will impact the overall project costs and delivery dates.

Any reconductoring works required on Energy Safe Victoria codified areas require insulated conductors if it exceeds 4 spans, this is to be decided during survey and detailed design and may impact the overall project costs and delivery schedule.

Technical assumptions and clarifications

The following technical assumptions and clarifications are made:

- Assumed $500 per site for signal strength testing.
- Assume one (1) pole replacement where new ACRs are required.
- Assume for the replacement of existing and new fuse saver, to allow for the following (per site):
    - One (1) new 14/12 concrete pole
    - One (1) new 16kVA 1ph pole mounted substation (incl. HV/LV earthing)
    - One (1) new control box
    - One (1) new modems & antennas
    - One (1) solar mounting kit
    - One (1) RCU battery
- Assume span lengths of 100m along sections of overhead lines that require reconductoring:
    - Assume 20% of poles require replacement
    - Assume 10% of new inter-pole required (for ACSR)
    - Assume 20% of new inter-pole required (for AAC)
    - Assume 15% of existing poles require replacement of their existing fittings and attachments
- Assume standard 4C 35mm^2 LV ABC where LV conductor is required.
- Assume any new concrete pole will require HV earthing (If an existing earthing is to be utilised for any existing pole, it is assumed that the earthing is deemed compliant with current standards).
- Existing poles and attached hardware including crossarms, insulators, fuses and transformers are assumed serviceable and excluded from this scope of works.
- Where multiple options are proposed, we have allowed for the most expensive solution. The preferred option will be determined during detailed design.

- A new pole mounted substation has been allowed for all new fuse saver installations. If local LV supply is available at the site, there is a possibility to use local LV supply for the Fusesaver control, which is to be decided at the detailed design.
- Allow for 15% of Fusesaver sites to require:
  - One (1) new 14/12 concrete poles
  - One (1) 60m spans of 4C 35mm LV ABC
- Assume the remaining 85% of Fusesaver sites will be adequate for solar LV supplies.