FINAL Decision Powercor Australia Contingent Project

Installation of Rapid Earth Fault Current Limiters (REFCLs) – tranche 1

August 2017

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Contents

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
BMP	Bushfire Mitigation Plan
BMR	Electricity Safety (Bushfire Mitigation) Amendment Regulations, 2016
capex	Capital expenditure
[C-I-C]	Commercial In Confidence
DELWP	Department of Environment, Land, Water and Planning
DNSP	Distribution Network Service Provider
ESC	Essential Services Commission (VIC)
ESV	Energy Safe Victoria
HV	High voltage
LTIC	Long term interests of consumers
Minister	Victorian Minister for Energy, Environment and Climate Change
opex	Operational expenditure
REFCL	Rapid Earth Fault Current Limiter
RIS	Regulatory Impact Statement
STPIS	Service Target Performance Incentive Scheme
VEDC	Victorian Electricity Distribution Code

Executive summary

On 28 March 2017 Powercor submitted an application to the Australian Energy Regulator (AER) for its revenue allowances to be adjusted for the installation of Rapid Earth Current Fault Limiters (REFCLs) in compliance with new Bushfire Mitigation Regulations (BMRs) introduced by the Victorian State Government. REFCLs are designed to reduce the risk of a bushfire caused by a fallen powerline.

The application seeks to recover project costs of $95.4 million ($nominal) for the first of three tranches of REFCL installation.[1] The proposed expenditure for tranche 1 is for:

- installation of REFCL devices at six zone substations
- replacement of equipment in the 22kv distribution network that is incompatible with REFCL operation and
- installation of isolating transformers to protect high voltage (HV) customers' equipment from damage due to increased voltages as a result of REFCL operation.

Our determination is that Powercor's revenue allowance should be amended to allow compliance with the amended BMRs. We do not accept the amount for which Powercor has applied. We have reduced the costs of this project by $10.2 million ($nominal). This is mostly because we consider the works associated with HV customers exceed the prudent and efficient costs necessary to implement these projects. We consider the excess should be excluded from the increase in Powercor's annual revenue requirement.

However, we have provided some allowance for HV customer works. Our decision is that we accept the position of the Victorian distribution businesses that they are liable under the Victorian Electricity Distribution Code (VEDC) for adverse effects to HV customers as a consequence of REFCL operation.

We understand the Essential Services Commission Victoria intends to conduct a review of the VEDC. We expect that review will affect the incidence or scope of this liability for future installations. However, the decision we make here must be based on the legislated requirements as they currently stand. Any change to VEDC requirements will be considered in the future, when we consider AusNet Services' applications for tranches 2 and 3.

If the VEDC requirements change before tranche 1 of this project is completed, and the change results in lower costs, a negative pass through event may transpire. This would reduce the revenue allowance to be recovered from customers, provided the applicable materiality threshold is met. Additionally, we have incentives in place for Powercor to outperform the benchmark allowances we set[2], including those allowed under this application. Under the Capital Expenditure Sharing Scheme, if capital savings are achieved for this project, 70% of the benefit is returned to customers through reduced prices in the years following the saving.

[1] Powercor contingent project application, REFCL program: tranche one, table 6.9. Comprises $91 m capital costs and $4.4 m in related overheads, which are expensed. Other operating costs are $1.1 m (All figures $nominal)

[2] In our Final Revenue Determination for Powercor's 2016-2020 regulatory control period

Our decision on works for HV customers (and capacitive loading issues at one zone substation) is only applicable for tranche 1 work program. It is not a precedent for the work proposed tranches 2 and 3. We will examine future tranches having regard to the circumstances then applicable.

Powercor also sought to recover expected operating expenditure of $5.7 million ($nominal) between 2017 and 2020. Our decision is that this expenditure is efficient and should be allowed.

Our determination is that Powercor can now recover the efficient cost of the tranche 1 REFCL installation project in charges during the remainder of the 2016–2020 period. The unsmoothed annual revenue requirement over the current regulatory control period will increase by $28.1 million ($nominal) to $3 204.9 million ($nominal). This will increase distribution network prices on average by 1.13% in 2018 and by 1.63% in each of 2019 and 2020.

In making our decisions we consider the National Electricity Objective, which is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers (LTIC) of electricity with respect to price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system. We consider this decision will serve the LTIC because:

- it's in the LTIC that the REFCL program is properly funded to meet the bushfire mitigation objectives of the Victorian Government for a safe, secure and reliable network but one that also avoids fire starts from falling or damaged assets and
- it's in the LTIC that to the extent the operation of REFCLs has any adverse implications for particular customers, that these are effectively and efficiently addressed by the DNSP – an efficient allowance has been made for that based on existing regulatory obligations, but one which will also encourage more efficient practices should regulatory changes be made.

Contingent project trigger event

Our Final Revenue Determination for Powercor's 2016-2020 regulatory control period included a trigger for 'Bushfire Mitigation Contingent Project 1' (tranche 1 of REFCL deployment) once the amended Victorian Bushfire Mitigation Regulations came into effect.[3] To be eligible to seek approval of the funding for the contingent project, Powercor is required to demonstrate the specified trigger event has occurred.

As set out in section 3.1, we consider that the requirements that comprise this trigger event have been satisfied.

Extension of time

Powercor submitted its application for this expenditure on 28 March 2017. The AER published the application for public comment on 4 April 2017. After review of the documentation provided with the application, we identified that the issues involved in

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[3] AER, *Final Decision, Powercor distribution determination 2016 to 2020*, Overview, p57

assessing this application were difficult or complex and required further consideration. Accordingly, we issued a notice to Powercor on 28 April 2017 advising that the AER would extend the time limit to make this decision to 21 August 2017.[4]

Assessment approach

We detail our assessment approach in section 2. In summary, in reaching our decision we relied on the following information:[5]

- Powercor's application
- a submission received from the Victorian State Government during public consultation
- Powercor's responses to our questions and related comments
- our own analysis and technical expertise
- the advice and assistance of Energy Safe Victoria (ESV) and the Essential Services Commission Victoria (ESCV)
- a letter received from ESCV[6]
- a report prepared for ESV by Marxsen Consulting and provided by ESV[7]
- two supplementary letters received from the Victorian Minister for Energy, Environment and Climate Change (the Minister)[8]
- a letter from the Department of Environment, Land, Water and Planning (DELWP)[9]
- our records of a roundtable meeting held on 3 August 2017 attended by AusNet Services, Powercor, the DELWP and ESV
- a letter from AusNet Services[10]
- two letters from Powercor[11]
- our records of a roundtable meeting held on 18 August 2017 attended by AusNet Services, Powercor, the DELWP, ESV and the ESCV.

We draw attention to a submission we received from the Victorian Minister for Energy, Environment and Climate Change supporting Powercor's application apart from funding distributors to install isolating transformers that would protect HV customer installations. The Minister also recommended the AER critically examine cost over-runs in number of areas and review the projects to ensure reliability benefits are taken into account, advocated that

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4 NER, Clause 6.6A.1(j)

5 See: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/powercor-contingent-project-installation-of-rapid-earth-fault-current-limiters-tranche-1

6 ESCV letter, *Amendment of the Electricity Distribution Code – Bushfire mitigation regulations C/17/10921*, 28/6/2017

7 Marxsen Consulting: *Customer assets directly connected to REFCL networks: a preliminary risk survey,* June 2017

8 As listed in Appendix A

9 As listed in Appendix A

10 As listed in Appendix A

11 As listed in Appendix A

the AER appoint independent expert technical advisers and asked that we conduct a detailed analysis of the proposals.

The Minister and the DELWP filed additional late submissions. Powercor filed responses to the late submissions. We took these submissions into account in making our decision.

AER determination

In accordance with clause 6.6A.2 of the NER, and taking into account stakeholder comments, our determination is that the bushfire mitigation tranche 1 contingent project should be approved, subject to adjustments to the capital and operating expenditure amounts sought. We consider that:

- the project as described is consistent with the contingent project approved in the 2016-20 revenue determination
- the trigger event specified for this project has occurred
- the capital amount sought exceeds the threshold specified in rule 6.6A.1(b)(2)(iii)
- an adjusted allowance for capital works intended to limit damage to HV customers through operation of the REFCL should be included in this project
- the operational expenditure reasonably required for the purpose of undertaking the project in each year of the regulatory period is $5.21 million (real, $2015) $5.68 million ($nominal)
- a better estimate of the capital expenditure reasonably required to complete the project is $77.3 million (real, $2015), i.e. $85.2 million ($nominal)
- the smoothed annual revenue requirement should be adjusted to $3 195.7 million total ($nominal) based on an unsmoothed annual revenue requirement of $3 204.9 million ($nominal) - an increase of 1.13% on average distribution network prices in 2018 and 1.63% in each of 2019 and 2020
- the X-factors should be adjusted as set out in section 5 to maintain the difference in the final year revenue (2020) of not more than 3%, consistent with the Powercor revenue determination and
- the project has commenced and the likely completion date is 1 May 2019.

Structure of this document

This document sets out our determination on the timing and amount of capital and incremental operating expenditure reasonably required within the current regulatory period to undertake this contingent project.

The decision is structured as follows:

- section one provides background, introduces the application and sets out our consultation process
- section two sets out our assessment approach

- section three sets out our assessment of the application by Powercor
- section four sets out the AER's calculation of the annual revenue requirement
- section five sets out the AER's determination.

1 Introduction

This section sets out the relevant background information to our determination. This is whether the contingent project trigger has been met and how AusNet Services' revenue allowance should be amended to meet its legal and licence obligations. For this application we conducted significant additional consultation and, in making our decision, took into account information that was provided in letters and meetings after our initial round of consultation.

1.1 Our role in this process

The Australian Energy Regulator (AER) is the economic regulator for electricity transmission and distribution services in the National Electricity Market (NEM), including in Victoria.[12] We are an independent authority, funded by the Australian Government. Our electricity-related powers and functions are set out in the National Electricity Law (Electricity Law) and National Electricity Rules (NER).

When we receive a contingent project application we publish the application and seek public comment. We assess the application to determine whether it contains the information required by the NER.[13] We examine evidence provided to determine if the mandatory pre-defined trigger event has occurred. We also examine whether the project before us is consistent with the contingent project approved in the revenue determination. We also analyse the application to determine if the costs proposed represent a reasonable forecast of the capital and incremental operating expenditure required for the purpose of undertaking the contingent project, both overall and in each year remaining in the regulatory control period. Where we have differed from the business' application we apply our adjustments to the post-tax revenue model to calculate the revenue the business may charge customers for the remainder of the regulatory period.

1.2 Powercor

Powercor is one of five distribution network service providers (DNSPs) in Victoria and is responsible for providing electricity distribution services in the western part of Victoria. We regulate the revenues Powercor and other electricity distributors can recover from their customers through determinations that cover the span of a regulatory control period. Powercor's current distribution determination is for the 2016-2020 regulatory control period.

1.3 Other regulators - Energy Safe Victoria and the Essential Services Commission (VIC)

Energy Safe Victoria (ESV) is the independent technical regulator responsible for electricity, gas and pipeline safety in Victoria. This includes administration of the *Electricity Safety Act*

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12 In addition to regulating NEM transmission and distribution, we also monitor the wholesale electricity and gas markets to ensure suppliers comply with the legislation and rules, taking enforcement action where necessary, and regulated retail energy markets in the ACT, South Australia, Tasmania (electricity only) and New South Wales under the National Energy Retail Law.

13 National Electricity Rules, clause 6.6A.2(b)(3)

1998 (VIC) and the *Electricity Safety (Bushfire Mitigation) Regulations 2013* (VIC). Distribution and transmission network service providers are required to submit a bushfire mitigation plan to the ESV for approval before 1 July of each year regarding powerlines identified as 'at risk' of starting fires. DNSPs required to upgrade their network to comply with the new bushfire mitigation provisions must also submit annual compliance reports to the ESV regarding their progress.

The Victorian Essential Services Commission is Victoria's independent regulator of the electricity, gas, water and sewerage, ports, taxis and rail freight industries. The Commission licenses energy retailers and distributors to operate in Victoria and administers the VEDC that all electricity distributors must abide by as a condition of their distribution licence. The VEDC includes provisions on quality and reliability of supply.

1.4 Bushfire mitigation reforms

In the wake of the tragic events of 2009's Black Saturday, the Victorian Bushfires Royal Commission published 67 recommendations[14] all of which were subsequently accepted by the Victorian State Government.

On 1 May 2016, the Victorian Parliament acted to carry out a number of the recommendations by passing amendments to the *Electrical Safety (Bushfire Mitigation) Regulations 2013*.[15] The amendments introduced new technical obligations on three Victorian distribution network service providers (DNSPs) that operate in high risk bushfire areas. These obligations include:

- each polyphase electric line originating from a selected zone substation must have the "*required capacity*" specified in the BMR
- testing for the required capacity must be undertaken before the specified bushfire risk period each year and a report detailing the results of testing submitted to ESV
- each new or replaced line with a nominal voltage from 1 kV to 22 kV inclusive must be covered or undergrounded from 1 May 2016 in 33 prescribed electric line construction areas
- each Single Wire Earth Return (SWER) line must have an Automatic Circuit Recloser (ACR) installed by 1 May 2023

Further, Schedule 2 of the legislation defines 45 *selected zone substations* and assigns a point value to each one based on the level of bushfire risk. Victorian DNSPs must meet the *required capacity* obligations for *selected zone substations* totalling:

- at least 30 points by 1 May 2019[16]
- at least 55 points by 1 May 2021[17] and

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14 Victorian Bushfires Royal Commission, *Final Report* (summary), July 2010, http://www.royalcommission.vic.gov.au/finaldocuments/summary/PF/VBRC_Summary_PF.pdf

15 *Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016* (VIC), http://www.legislation.vic.gov.au/Domino/Web_Notes/LDMS/PubStatbook.nsf/93eb987ebadd283dca256e92000e4069/9CC083A75311B617CA257FA100148082/$FILE/16-032sra%20authorised.pdf

16 Or all *selected zone substations* if less than 30 points of a DNSP's substations are defined in Schedule 2.

- any remaining selected zone substations by 1 May 2023.

The ‘required capacity’ for a polyphase line originating from a *selected zone substation* is defined by the legislation as:

> *‘…in the event of a phase-to-ground fault on a polyphase electric line, the ability—*
>
> *(a) to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for high impedance faults to 250 volts within 2 seconds; and*
>
> *(b) to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for low impedance faults to—*
>
> *(i) 1900 volts within 85 milliseconds; and*
>
> *(ii) 750 volts within 500 milliseconds; and*
>
> *(iii) 250 volts within 2 seconds; and*
>
> *(c) during diagnostic tests for high impedance faults, to limit—*
>
> *(i) fault current to 0.5 amps or less; and*
>
> *(ii) the thermal energy on the electric line to a maximum* I^2t *value of 0.10*[18]

In addition, increased compliance incentives were introduced on 11 May 2017 when the Victorian State Parliament passed the *Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme) Act 2017*. The Act introduces civil penalty provisions for the new requirements on DNSPs both as a single fine for a particular contravention and additional fines for each day the contravention remains unresolved.

1.4.1 Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016 - Regulatory Impact Statement

On 17 November 2015, a Regulatory Impact Statement (RIS) on the *Electricity Safety (Bushfire Mitigation) Amendment Regulations* was released by the Victorian Department of Economic Development, Jobs, Transport and Resources (DEDJTR).[19]

The RIS identified that the proposed regulations would impact Powercor and AusNet Services significantly (as the operators of the vast majority of rural powerlines in Victoria), with Jemena impacted to a much smaller degree. Its analysis was based on installation of a REFCL device at each of the 45 selected substations. The RIS analysis is based on REFCLs as this is the only technology currently available that can meet the specifications for dealing with a phase to ground fault in the BMR.

The RIS[20] estimated the complete cost required to carry out the necessary REFCL installation program (in 2015 dollars) for each DNSP was:

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[17] Or all *selected zone substations* if less than 55 points of a DNSP’s substations are defined in Schedule 2.

[18] *Electricity Safety (Bushfire Mitigation) Regulations 2013* (VIC), Regulation 5, ‘Definitions’.

[19] http://www.acilallen.com.au/cms_files/ACILAllen_BushfireMitigationRIS_2015.pdf

- AusNet Services (22 named zone substations) - $140.0 million [$146.6 million ($nominal)]
- Powercor (20 named zone substations) - $154.5 million [$161.8 million ($nominal)]
- Jemena (3 named zone substations) - $2.2 million [$2.30 million ($nominal)]

These estimates are for the total program of work across three tranches of contingent projects for each DNSP.

The RIS acknowledged that some equipment belonging to HV customers directly connected to the 22kV network may need to be replaced as a consequence of REFCL installation at the zone substation. From information provided by the DNSPs we understand that there are 92 HV customers connected directly to the 22kV network across the 45 named zone substations. The RIS estimated cost of $100 000 (real, $2015) [$104 700 ($nominal)] for each of the 92 HV customers for replacement of surge arresters and voltage transformers. The RIS stated that these costs would be incurred by HV customers.

1.4.2 Previous AER assessments relating to this application

In Powercor's Final 2016-2020 Distribution Determination, the AER included funding for REFCL installation trials at Woodend and Gisborne zone substations. [21] Powercor was obligated to undertake these trials, which formed part of its BMP.

As part of the AER's 2016-2020 distribution determination decision for Powercor, trigger events were defined for three successive Bushfire Mitigation contingent projects during the 2016-2020 regulatory period.[22] These Bushfire Mitigation contingent projects relate specifically to expenditure required to comply with Victorian bushfire regulations that prescribe the installation of REFCLs and associated works.

1.5 Powercor's application

On 28 March 2017, Powercor submitted a contingent project application for funding to install REFCLs at 6 zone substations and for other associated works including the replacement of 10,876 surge arrestors. Powercor have split their programme of REFCL installations across their 20 named zone substations into three tranches. These tranches align with the three dates provided in the new bushfire legislation by which a certain proportion of the named zone substations must meet the required capacity for phase to ground faults (1 May 2019, 1 May 2021 and 1 May 2023). The first tranche, which is the subject of this contingent project application, is for works to be completed and operational by 1 May 2019.

We published the application for public comment on 4 April 2017. Consultation closed on 8 May 2017. We identified that the issues involved appeared difficult or complex. Accordingly, we issued a notice to Powercor on 28 April 2017 advising that the AER would extend the time limit to make this decision to be on or before 21 August 2017.

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[21] AER, *Final decision, Powercor distribution determination 2016-20, Attachment 6 – Capital Expenditure*, p. 134

[22] AER, *Final decision, Powercor distribution determination 2016-20, Attachment 6 – Capital Expenditure*, p. 144

The contingent project for tranche 1 relates to REFCL installation works at the following zone substations:

- Camperdown
- Colac
- Castlemaine
- Maryborough
- Winchelsea
- Eaglehawk

The proposed total capital cost is $95.4 million ($nominal) for the 6 projects.[23] Powercor forecast an increase in opex of $5.7 million ($nominal).

Powercor sought the following expenditure and revenue requirements to deliver the contingent project.

Table 1.1: Contingent project revenue requirement, 2016-20 million ($nominal)

	2017	2018	2019	2020
Return on capital	0.1	3.2	5.6	5.4
Return on capital (regulatory depreciation)	0.0	2.3	3.1	3.3
Operating expenditure	2.2	2.3	0.4	0.8
Net tax allowance	-0.0	0.3	0.3	0.4
Annual revenue requirement (unsmoothed)	2.2	8.2	9.5	9.9
Annual revenue requirement (smoothed)	0.0	9.6	10.0	10.5

Source: Powercor Contingent Project application, REFCL program (tranche one), 28 March 2017, table 1.1, p.7.

1.5.1 Points of difference between the RIS and Powercor's application

Powercor identify the differences in costing between the figure proposed in the contingent project application and the figure given in the RIS as due to some works being underestimated and others not being considered at all. The AER has found there is no material disparity between the RIS and the contingent project application for the costing of specific items. However, we have found that there are departures in the volumes of work associated with a number of items, which has significantly affected costs. In addition, there is a significant additional allowance sought for the installation of HV isolation transformers.

23 We note that Powercor was allocated funding for ACR installation in their 2016-20 Electricity Distribution Price Review.

High Voltage isolation transformers

High Voltage (HV) customers connected directly to the 22kV network where REFCLs are installed risk damage to their equipment due to voltage spikes that occur when a REFCL is in operation. When a REFCL detects a fault due to a fallen powerline, it redirects the current flowing through the fallen phase to the remaining phases thereby reducing the chance of bushfire starts. However, this increases the voltage of the remaining phases, potentially beyond the limitations of a HV customer's connected equipment. Consequently, Powercor have included a cost for the installation of 25 isolation transformers of $21.6 million ($nominal) to prevent HV customers being at risk of overvoltage in their installations when the REFCL operates.

The Minister and DEWLP do not support Powercor's proposal to address HV customers' risks.

The RIS estimated a cost of $100 000 (real, $2015) [$104 700 ($nominal)] per customer for the replacement of surge arresters and voltage transformers for each of the 92 HV customers across Victoria. These are customers identified as being directly connected to the 22kV network across the 45 zone substations where REFCLs are to be installed.

Other costs

Compared to Powercor's contingent project application, we have found the RIS underestimated the cost of, or did not include costs for:

- extensive line capacitive rebalancing works
- increased number of surge diverters to be replaced (due to REFCL operation increasing line voltage)
- undergrounding
- protection modification
- line replacement works
- procurement of land to house additional equipment
- zone substation rebuilding
- the installation or modification of switchboards
- HV customer isolation

1.5.2 AER view of the RIS and regulatory framework

We note that the RIS was prepared in 2015, largely based on preliminary costing information provided by the DNSPs. We have investigated the reasons for the differences between the preliminary costing and the more detailed scope of works assessments which are now available. We are satisfied that the increased volumes of work are well substantiated and should be accepted.

In this decision we have also accepted that, under the current Victorian safety regulation framework, there is a requirement for HV customer isolation. However, we have not been satisfied the whole of the allowance claimed for this work has been wholly justified.

This decision is based on our assessment of the current Victorian regulatory framework as at the time of this decision. We anticipate changes will occur to that framework which will affect the future need for HV isolating transformers.

1.6 Why did Powercor request the AER to make a determination?

In its 2016–20 distribution determination proposal, submitted to the AER on 30 April 2015, Powercor sought to include two contingent projects for the new bushfire regulatory obligations mandating a REFCL installation program, which were in development at that time.[24] We did not agree with Powercor's proposed trigger event. Powercor's final 2016-20 distribution determination divides the contingent project into three tranches and settles upon the final form of the trigger event.

Contingent projects are significant network augmentation projects that may arise during the regulatory period but are not yet committed and associated costs are not sufficiently certain such that the expenditure should form a part of our assessment of the total forecast capital expenditure that we approve in a reset determination. Contingent projects are linked to unique investment drivers, which and are defined by a unique 'trigger events' that are set by the AER when it determines to accept a proposed contingent project in a revenue proposal.[25]

If the trigger for a contingent project occurs, the network service provider may apply to the AER to amend its revenue determination to include the capital and operating components required to undertake the project in the current regulatory period. The AER must determine if the proposed costs are prudent and efficient.[26] The AER must also determine the total cost of the project to be incurred in each remaining regulatory year of the current regulatory control period.[27] It is common ground amongst all the parties we consulted that the trigger event has occurred. In making this decision we have had regard to the requirements of clause 6.6A.2(e)(1), taking into account the factors in clauses 6.6A.2(f) and 6.6A.2(g) and the requirements of clause 6.6A.2(h).

1.7 Our initial consultation process

For the purpose of seeking public comment, the AER is required to publish an application for a contingent project as soon as practicable after it has been received. Any written submissions received must be considered by the AER before making a decision on the application.

24 Powercor – *Regulatory Proposal 2016-20,* 30 April 2015

25 National Electricity Rules, clause 6.6A.1(c)

26 National Electricity Rules, clause 6.6A.2(g)(4)

27 National Electricity Rules, clause 6.6A.2(e)(1)

Following the publication of the contingent project application, the AER received a submission from the Victorian Minister for Energy, Environment and Climate Change. The Minister supported the overall application, but recommended the AER carefully examine cost over-runs, review the projects to ensure reliability benefits are taken into account and asked that we conduct a detailed analysis of the proposals. We examine these aspects in detail in section 3.4 below, where we review specific project cost elements. The Minister also advocated that the AER appoint independent expert technical advisers.

The following items were identified as requiring specific examination on account of assumed excessive expenditure or being directly related to areas of costs where prior funding has been approved:

- zone substation works at one (Winchelsea) of the six Tranche 1 zone substations, in the light of prior re-build project works for the same zone substation;
- program management related costs of $5.7 million ($nominal) which include project management office costs, which are far in excess of similar costs estimated by AusNet Services.[28]

Importantly, the Minister did not support the inclusion of additional funds in the contingent project for distributors to conduct work to isolate HV customer installations without technical due diligence. In particular, the Minister did not support the blanket installation of HV isolating transformers. This emerged as a significant issue in the further stages of our review and involved several stages of further consultation.

1.7.1 Further consultation on compliance with the Victorian Electricity Distribution Code

Significant issues were raised by both AusNet Services and Powercor regarding compliance with the VEDC, and as a result we conducted further consultation. We also received further written advice from stakeholders.

1.7.1.1 Essential Services Commission of Victoria

We wrote to the ESCV in mid–May to clarify their intentions to amend the VEDC in response to the new legislation. We requested the ESCV's advice on whether a review of the VEDC will incorporate amendments to account for the operation of REFCL devices on the Victorian electricity distribution system. The ESCV responded it plans to review relevant parts of the VEDC and expects to begin this review in the latter part of 2017. They stated that any changes to the VEDC would be consistent with the BMR. However, given its obligations under its legislative process to consult and to consider matters before making a decision, it could not provide guidance on specific VEDC changes it may make nor on how these changes may affect future financial liability.

[28] Victorian Minister for Energy, Environment and Climate Change, Submission, 8 May 2017

1.7.1.2 Powercor

Powercor raised a number of issues about its ability to comply with the VEDC in relation to their HV customers:

- when a REFCL detects a fault, the REFCL drives the voltage on HV lines to a level greater than a limit specified in the VEDC and for a time period longer than permitted by the VEDC. The risk of potential voltage impacts from REFCL operation on HV customers was identified in the RIS and the costs estimated to HV customers therein were based on the presumption the DNSPs can easily access and upgrade the customer installation to counter the effect.

Powercor submitted[29] the presumption of working with HV customers to ensure their installations can safely accommodate the elevated voltage during REFCL operation is not a viable option for Tranche 1 because:

> *'We are not aware of alternative solutions to maintaining compliance (or protecting HV customer assets) that can be implemented on our side of the connection point and not result in large numbers of planned and unplanned outages for the HV customer. This includes consideration of clauses in our deemed distribution contract—in particular, although customers must ensure their electrical installations comply with our reasonable technical requirements, the contract clearly states we must comply with the obligations imposed on us under the Code (and as such, deemed distribution contracts do not provide relief for us on this matter).'*

Powercor also argued that under clause 4.2.7 of the VEDC, that they also face financial liability for voltage variations that are outside the limits specified in the VEDC.

We consulted with the Essential Services Commission Victoria (ESCV, who has authority over the Code), the Department of Environment, Land, Water and Planning (DELWP), and Energy Safe Victoria (ESV) on different occasions in May and June to examine the matters raised by Powercor in relation to compliance with the VEDC.

1.7.1.3 Energy Safe Victoria

On 26 June 2017 Energy Safe Victoria provided the AER with a report by Marxsen Consulting entitled "*Customer assets directly connected to REFCL networks: a preliminary risk survey*". This report examined twelve customers of AusNet Services and Powercor whose HV installations would require modification to allow operation if directly connected to a REFCL protected distribution network. ESV also provided this report to AusNet Services, Powercor and to the Victorian Minister for Energy, Environment and Climate Change and sought replies from those parties. The AER was not asked to respond to that consultation and we did not make a submission.

The relevant findings of the Marxsen report are: [30]

> *This review of customer assets indicates that, recognising the small size of the sample:*

[29] Powercor *Contingent Project Application REFCL program: tranche one March 2017* p47

[30] Marxsen Consulting , *Customer assets directly connected to REFCL networks: a preliminary risk survey, June 2017,* p3

1. *The primary bushfire ignition risk is a cross-country fault should a customer asset fail to withstand higher than normal voltages during REFCL response to an earth fault elsewhere on the network.*
2. *The consequences of a cross-country fault can include:*
    a. *In high fire risk conditions, a fire at the site of the original fault. However, this is unlikely if either the original fault is not of a type that would normally cause a fire, or it is not a sustained fault.*
    b. *Customer asset damage with*
        i. *Potential risk of interruption to normal site activity, lost production and potential loss of stock due to loss of supply.*
        ii. *Potential risk of injury or death of anyone exposed to the failed asset at the time.*
    c. *Network asset damage and consequential loss of supply to other customers.*
3. *Cross-country faults have proven to be rare in the only REFCL network operating in Victoria over the past five years (perhaps one per cent of all earth faults).*
4. *Risk from customer assets represents a small increment (perhaps three per cent) of Victoria's total risk from cross-country faults.*
5. *Safety risk from customer assets is of the same nature and likely no greater 'per asset' than that arising from the same assets deployed in distribution networks.*
6. *Risks from customer assets may in many cases be cost-efficiently mitigated without isolation transformers between the customer site and the distribution network.*
7. *Customers and network owners have a common interest in prevention of asset failures. Mitigation costs may be reduced by early technical information sharing and collaboration.*
8. *Clarity about the boundary between customer assets and network assets would strengthen accountability for safety risks.*

ESV received responses from AusNet Services[31] and Powercor[32] which are published on the ESV website. Although noting the Marxsen report was useful, both DNSPs maintained their view that HV isolating transformers were a preferable solution. For example, AusNet Services said the Marxsen report did not cover:

- liability and regulatory considerations
- economic and financial consequences of supply reliability factors
- compliance with Victoria's Electricity Distribution Code without any requirement for negotiation

[31] http://www.esv.vic.gov.au/pdfs/ausnet-services-response-hv-customers-and-refcl-protected-networks-report-june-2017/

[32] http://www.esv.vic.gov.au/pdfs/powercor-response-hv-customers-and-refcl-protected-networks-report-june-2017/

- specialised technical requirements and
- alignment with REFCL rollout timelines.[33]

1.7.1.4 Minister for Energy, Environment and Climate Change

On 27 July 2017, the AER received a letter from the Minister for Energy, Environment and Climate Change, which supported the Marxsen view.[34] The Minister stated that the Marxsen report does not support the installation of isolating transformers at any of the twelve sites surveyed in the report. Rather, the Minister cited the preferred option being for the distributors to commence working with HV customers now to discover suitable network hardening mitigations.

The Minister also noted the VEDC is to be reviewed and asked that the AER to take this factor into account in assessing these applications. Finally, the Minister went on to note that fair and serious consideration would be given to timeline extensions[35] under the *Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme) Act 2017* should it emerge that any delay was due to factors outside the control of the DNSPs.

On 1 August 2017, Powercor replied to this letter. In their reply Powercor stated the need to comply with the VEDC and the regulatory framework remained a significant concern.[36]

1.7.1.5 Roundtable meeting on 3 August 2017

To provide the key stakeholders an opportunity to resolve these divergent views, on 3 August 2017 the AER convened a roundtable meeting. Attending were the CEO and senior staff of AusNet Services, Powercor and ESV. Also attending were senior staff of DELWP, representing the Minister and the Board and senior staff of the AER. The meeting was chaired by the Chair of the AER.

AER staff noted the following points during discussion.

Each business advised that although the HV isolating transformers were a costly option, they had arrived at this approach based on a number of factors including:

- a need to comply with the VEDC as it exists today
- no certainty as to the scope of changes planned for the VEDC
- under the VEDC, the DNSP bears a financial liability for damage if a customer is exposed to voltages outside the limits set by the VEDC
- time pressure to complete the works to a mandated timetable
- uncertainty whether the Victorian penalty compliance regime would apply

33 *AusNet Services response – HV customers and REFCL protected networks report June 2017.pdf*, pp.2-3

34 Letter, Minister for Energy, Environment and Climate Change, Victoria, 27 July 2017

35 Technical exemptions are available under section 120W. These can only be granted by Governor in Council. From 1 September 2017, these provisions sit under Part 10A of the Electricity Safety Act 1998.

36 Powercor, letter, 1 August 2017 – as listed in Appendix A.

- risk to their reputation if they fail to deliver on time
- lack of knowledge of, and access to, customer installations
- poor or no incentive for customers to cooperate
- legal risk of being joined to actions should a fire event occur and
- knowledge the HV isolating transformers were an effective solution.

Both DNSPs pointed out that if savings were made, the regulatory incentive regime would return the bulk of any savings to customers.[37]

DELWP presented the alternative case that:

- the Marxsen report confirmed lower cost options were possible at most sites
- HV isolating transformers was not the only technology that could achieve the desired outcome
- hardening works as detailed by Marxsen would enable REFCL protection to extend to HV customer network assets
- a key consideration should be to minimise the costs but the HV isolating transformers were unduly expensive as a blanket option
- the ESCV had stated the VEDC will be amended and those amendments would address the need to make the VEDC compatible with the operation of REFCLs
- the Minister has indicated that relief from the compliance regime is likely if the DNSPs were diligent in their efforts to meet the timetable and
- alternative technological solutions may be feasible.

The DNSPs did not agree the alternative technology suggested by DELWP was feasible because it would adversely impact customer reliability and was inconsistent with their obligation to maintain customer reliability.

ESV stated that from a safety perspective, either technology - network hardening or customer isolation - would be acceptable.

The meeting also discussed the purchase arrangements and costs proposed for isolating transformer purchases and installation. The DNSPs advised that:

- they need to engage with local suppliers only, on a limited basis
- time pressure and the unique nature of the HV isolating transformers meant normal purchasing by competitive tender was not a feasible option
- a price premium was inevitable regardless of the supplier because this was not a mass produced item

[37] The Capital Expenditure Sharing Scheme returns 70% of the benefit of a capital saving to customers.

- their suppliers were unlikely to price excessively because that would place them at risk of a loss of future business
- land purchase and easement costs were another significant expense.

AER staff asked about cost estimates that had been provided, giving the example of HV regulating transformers. They noted that:

- the approach taken to arrive at the transformer cost estimates appeared to be reasonable in the circumstances
- various of the DNSP estimates included duplicated strain poles, and that a single pole could suffice[38]
- land costs used were urban rates but in many cases the locations were rural
- AusNet Services was using “wet bund” transformer designs when “dry bund” as proposed by Powercor was significantly cheaper
- overall allowances for design, installation and commissioning appeared excessive relative to the HV transformer regulator costs and
- the secondary protection requirements were necessary.

Further discussion turned to the issue of “cross country”[39] faults. AER staff stated a key concern was how the problem of the financial liability of a distributor should a cross country fault trigger a fire event had not been resolved. Although this risk was not large, Marxsen had estimated the effect at 3%.[40] We asked if this risk was insurable. The DNSPs each replied that until the VEDC was amended, they would not have a solid basis to discuss this matter with insurers.

The AER concluded the meeting with an offer to consider any final submissions from any stakeholder on a matter raised in this meeting, to be received by 7 August 2017.

We received a letter from DELWP on 16 August 2017, which reiterated the points they raised at the roundtable meeting on 3 August 2017.

1.7.1.6 Meeting with ESCV

AER staff met with the ESCV on 16 August 2017. The ESCV explained the process they intend to follow to review the VEDC, to adapt it to recognise, and be consistent with, REFCL operation. In this context, ESCV advised their view was that AusNet Services would not face a compliance liability if a REFCL caused voltage excursions outside the current limits contained in the VEDC.

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38 A “strain pole” is a special pole construction. It is used where a line ends to counter the weight of a line which is on one side only. If a gap or space is created between two spans, two poles are required – one at each end, which adds significantly to costs. We consider the option of using a single pole with no gap is adequate for this project.

39 A “cross country” fault is a second fault that can arise on a network, potentially triggered by the operation of a REFCL dealing with an initial fault. This fault can be more serious than a primary fault as the REFCL operating mode may raise the line voltage up to 90% over the normal operating voltage.

40 Marxsen, op. cit., recommendation 4.

Based on this update and earlier meetings and correspondence with ESCV, we accept this advice.

1.7.1.7 Letter from the Victorian Minister for Energy, Environment and Climate Change

On 17 August 2017, we received a second letter from the Victorian Minister for Energy, Environment and Climate Change.[41] In this letter, the Minister announced the Victorian Government's plan to establish a $10m fund to assist HV customers mitigate risks to their equipment from the operation of REFCL. The fund is intended to support HV customers make changes to their installations to function safely in concert with the REFCL devices.

On the basis of this fund, the Minister proposed that AER funding of works by Powercor and AusNet Services to isolate HV customers would not be necessary, and that the AER should not approve this expenditure for recovery under AusNet Services' application for this contingent project.

1.7.1.8 AusNet Services and Powercor letters

On 18 August 2017, we received letters from both AusNet Services and Powercor, which responded to the Minister's letter referred to in 1.7.1.7. The DNSPs expressed concern that the proposed fund did not adequately address compliance issues, that there remained significant delivery risk, and that the scope for financial liability to be incurred by the businesses remained. Powercor also raised a concern that the Minister's letter had arisen late in the process and they did not have a reasonable opportunity to respond to this new material.

1.7.1.9 Roundtable meeting on 18 August 2017

To consider the Minister's further advice, on 18 August 2017 we reconvened the key stakeholders in a second meeting. In addition to the stakeholders listed in the earlier roundtable meeting, a senior officer of ESCV also attended.

The meeting discussed the government's plan for a fund to support HV customers. DELWP explained that the fund would operate in stages, firstly to identify potential works on customer sites and then a second funding stage, whereby grants would be made available to help fund works identified in stage 1 on a case–by–case basis. The meeting also discussed the provisions available under the BMR and Essential Services Act to manage compliance issues that may arise as the program evolves.

The ESCV pointed to clause 16 (c) of the VEDC that requires customers to take reasonable precautions to minimise the risk of damage to any equipment which may result from poor quality or reliability of electrical supply. They also noted that while they could not pre-empt the outcome of a process to amend the VEDC, under the Essential Services Act, any amendments would need to be consistent with the BMR.

We observed that the DNSPs view was that the fund was a positive step which would support work to make REFCL installations effective although they expressed concern that the fund would not remove all financial liability, particularly the potential for legal liability.

[41] See Appendix A – Late submissions.

The DNSPs advised that they must act on the basis of the obligations contained in the Victorian compliance framework and that they could not rely on the exercise of discretions in the event of any non-compliance.

The ESV advised that it would not approve the operation of the REFCLs until it was confident that they could be operated safely from a network and HV customer perspective.

1.7.1.10 AER assessment

The AER must make its funding decision within a legislated limited time period. Our decision must be made no later than 21 August 2017.[42] Our decision must be based on the obligations the DNSPs face currently, or are known will apply, at the time the expenditure will be required. Although our preference would be for the VEDC to be amended by the ESCV before we must decide this current application, this has not been possible. The earliest ESCV will consult on the matter is in late–2017 with a decision likely in 2018, well after this decision is required to be made.

We accept that any amendments of the VEDC would need to be consistent with the BMRs. However we cannot pre-empt the timing or the outcome of any amendments to the VEDC and we must consider the applications based on the VEDC as it is currently written.

We understand that it is within ESCV's control to issue "no action" for any potential breach of the voltage limits caused by the operation of REFCL.

We note that the timetable for completion of the tranche 1 is set out as obligations in Powercor's BMP.[43] ESV can issue "no action" for a breach of the obligations now contained in Powercor's BMP. However, we agree with the DNSPs that the issue of "no action" letters by ESCV and ESV may not relieve them of all liability should the operation of the REFCL cause damage to HV customer equipment or bushfires. Further, the DNSPs argued that these may not be insurable risks given that the operation of the REFCL would knowingly breach the VEDC.

Therefore, we have determined that some allowance for the installation of isolating transformers is appropriate.

We consider a prudent business would act on the basis that it must install and operate its network in accordance with the current Victorian regulatory framework, notwithstanding that the framework is subject to change. We consider it highly likely that the framework will change in the foreseeable future and those changes will affect the approach to this issue in all future tranches of these works. We also note the Victorian Government's commitment to create a fund to support HV customers adapt their installations to operate safely with REFCLs. We consider this fund, when it is established, is likely to significantly assist in mitigating the financial risk the DNSPs face.

Under the current Victorian regulatory framework, operation of a REFCL will breach the VEDC requirements and carries with it the risk of financial liability if damage to customer installations were to occur. Although this liability may be reduced by the operation of clause 16(c) of the VEDC, this clause is currently linked to the current limits in table 1 of the VEDC.

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42 NER clauses 6.6A.2 (j)

43 The Powercor Bushfire Mitigation Plan as accepted by Energy Safe Victoria at 28 March 2017.

Until table 1 is amended, operating a REFCL will cause over-voltage events to occur which exceed the maximum permitted values and which currently, the customer installation should be capable of withstanding. Therefore, it is not clear that clause 16(c) will be effective in limiting financial liability for damage to a customer installation.

Further, the framework is supported by a civil penalty regime if the mandated completion date of 1 May 2019 is not achieved. A prudent business would operate on the basis that the financial liability may be significant and that the penalty regime will apply. This remains the position of both Powercor and AusNet Services, notwithstanding that Victorian officials gave a significant indication that if the cause of a delay were outside the control of the DNSPs it was unlikely any penalties would be applied.

Powercor and AusNet Services both argue they cannot be expected to speculate whether a future independent decision maker would accept the penalty regime might be waived, even if their reason for a delay in meeting the mandated operating date (1 May 2019) was because of factors outside their control. A relevant factor here may be that one or more customers had failed to upgrade their installations in time. Another relevant factor to each DNSP is that the delay would occur in circumstances where a reliable alternative was available (the HV isolating transformer) but not adopted.

Also, we note that Powercor (and AusNet Services in relation to its own circumstances) argue that even if VEDC compliance is achieved, there remains a risk at law of financial liability if equipment owned by Powercor were to trigger a failure in customer equipment and that failure led to a fire event. If a Powercor REFCL triggered a fault in a customer installation which could have been avoided, Powercor is likely to be sued directly or joined to any ensuing legal action. This may become an insurable risk in the future, but this cannot be ascertained until the VEDC is amended.

Although hardening of customer installations is a potentially viable approach in the longer term and could lead to lower project costs, further changes are required to the Victorian regulatory framework for this to be completely viable. We consider, therefore, that this decision is not a precedent for future tranches of, or other decisions about, similar work. Each tranche or decision must be considered on its merits based on the relevant obligations and requirements applicable at the time.

Powercor operates under an incentive regime which continuously encourages them to find better and cheaper ways to deliver services. Our role is to set an efficient allowance for the completion of these works which forms a benchmark that Powercor will seek to better. If they succeed, under the Capital Expenditure Sharing Scheme, customers will receive 70% of the benefit of any savings whilst Powercor will retain 30%. Also, the benefit of these efficiency gains will inform future projects and result in long-term gains for customers.

1.7.1.11 AER HV customer works cost estimate approach

We agree with Marxsen that the hardening approach is preferable although this requires detailed cooperative work between the DNSP and the customer. We note that at some sites, particularly large load or generator sites, the most cost effective option may be to install a HV isolating transformer. However, without a detailed investigation of every affected customer site, the AER is unable to reliably cost this hardening work.

The cost of customer side work is estimated by Marxsen to be very variable, ranging from $20 000 to $3 million per customer. With such wide variability, a reasonable allowance based on a simple average of the Marxsen range could exceed the allowances claimed by Powercor. Even a weighted average is unlikely to be suitable. This is because there is no basis to establish if the sample of customers on which the Marxsen report is based is representative of all affected customers. In the absence of detailed information, we do not consider it reasonable for the AER to attempt to set an allowance based on an averaging approach. We note that at the second roundtable meeting it was agreed the Marxsen sample was not statistically representative of all customers.

Accordingly, we determined an alternative forecast based on our consideration of similar distribution equipment with comparable design, location and installation requirements as the HV isolating transformers proposed by Powercor. In particular, we have used the HV regulating transformer as a point of reference in our decision.

Our decision on this cost element is discussed further in section 3.4.1.5 of this decision.

2 Assessment approach

In the first submission on Powercor's application by the Victorian Government Minister for Energy, Environment and Climate Change it was recommended that we commission an independent expert review of the costs proposed by Powercor.

We reviewed the project application to establish the types of technical expertise required. We determined we required distribution design expertise and advice on REFCL technology. REFCLs are a new technology and there is only a limited supply of specialist personnel available to provide support for its implementation. However, the available personnel have conflicts of interest. Some are employed by the applicants whilst the remainder were employed by the Victorian Government to develop the technology. Consequently, we concluded that an independent expert technical adviser on REFCL implementation would not be available to assist with this decision. Our internal technical advice team was used instead, with additional support from a contractor with specialist skills in distribution design engineering. We also relied on the advice of the Victorian regulatory bodies, Energy Safe Victoria and the Essential Services Commission Victoria.

We examined the material presented by Powercor in its application. We assessed the completeness of the information and identified a number or areas where we needed additional information to support the business' claims. However, we assessed the information provided in the application to be sufficient to be accepted as a compliant application for the purposes of clause 6.6A.2(b) of the NER.

We issued a number of sets of questions to Powercor. We examined Powercor's responses and prepared follow up questions and also assessed those responses. We also conducted our own analysis of the sub-projects as set out in the application.

2.1 National Electricity Rules requirement

The Electricity Rules state a contingent project application must contain the following information[44]:

(i) an explanation that substantiates the occurrence of the trigger event;

(ii) a forecast of the total capital expenditure for the contingent project;

(iii) a forecast of the capital and incremental operating expenditure, for each remaining regulatory year which the Distribution Network Service Provider considers is reasonably required for the purpose of undertaking the contingent project;

(iv) how the forecast of the total capital expenditure for the contingent project meets the threshold as referred to in clause 6.6A.1(b)(2)(iii);

(v) the intended date for commencing the contingent project (which must be during the regulatory control period);

[44] National Electricity Rules, clause 6.6A.2(b)(3)

(vi) the anticipated date for completing the contingent project (which may be after the end of the regulatory control period);

(vii) an estimate of the incremental revenue which the Distribution Network Service Provider considers is likely to be required to be earned in each remaining regulatory year of the regulatory control period as a result of the contingent project being undertaken as described in subparagraph (iii);

In assessing the application the AER must take into account:[45]

(1) the information included in or accompanying the application;

(2) submissions received in the course of consulting on the application;

(3) such analysis as is undertaken by or for the AER;

(4) the expenditure that would be incurred in respect of a contingent project by an efficient and prudent Distribution Network Service Provider in the circumstances of the Distribution Network Service Provider;

(5) the actual and expected capital expenditure of the Distribution Network Service Provider for contingent projects during any preceding regulatory control periods;

(6) the extent to which the forecast capital expenditure for the contingent project is referrable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms;

(7) the relative prices of operating and capital inputs in relation to the contingent project;

(8) the substitution possibilities between operating and capital expenditure in relation to the contingent project; and

(9) whether the capital and operating expenditure forecasts for the contingent project are consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8, 6.5.8A or 6.6.2 to 6.6.4.

Further in making this decision we have had regard to the requirements of clause 6.6A.2(e)(1), taking into account the factors in clauses 6.6A.2(f) and 6.6A.2(g) and the additional requirements of clause 6.6A.2(h).

2.2 AER approach

We followed the approach set out in the NER clause 6.6A.2.

We examined whether the project trigger event had been satisfied. We concluded that it had. We tested whether the amount sought exceeded the threshold for a contingent project and concluded that it had, as set out in rule 6.6A 1 (b) (iii). The AER then reviewed the application and public submissions.

We identified a number of issues to investigate. These centred on:

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45 National Electricity Rules, clause 6.6A.2(g)

- differences between the RIS estimate and the application
- differences between the AusNet and Powercor contingent project applications
- the technical approach
- VEDC compliance and the HV customer isolation requirement
- levels of complexity required and discrimination between REFCL driven expenditure and reliability objectives already incentivised under the STPIS program
- discrimination between DNSP obligations and specific REFCL related statutory compliance obligations
- capex vs opex balance
- identification of any costs that have been included in the revenue determination, if any
- treatment of depreciation
- estimating techniques
- governance

Questions addressing these issues were issued to Powercor. Written responses were provided. AER asked further questions to clarify some aspects of the replies that remained unclear. Emails were used to respond to these questions.

We considered whether a prudent and efficient network business would have structured the project in similar or different form to that proposed by Powercor.

We concluded with some exceptions that they would.

Powercor has provided detailed cost estimates and has advised us that there are no restrictions on information provided. Their only requirement is that customers cannot be identified. We acknowledge this level of transparency and accept the commercial in confidence nature of customer information. This approach is also consistent with our confidentiality guideline.

The AER's Technical Advisor Group (TAG) is an internal group of experts that provides the AER with insight and advice into electricity supply industry decision making, design and operating practices and costs. We sought the TAG's advice to assist us in making this determination. They examined how estimates were developed and identified weaknesses with the Powercor and AusNet Services approach in some instances.

We considered the application of STPIS incentive schemes under the NER and performed analyses to ensure that there was not a conflict between REFCL driven modifications and those normally driven by reliability incentives.

Having determined the required capital and operating expenditure necessary to complete the project, we modified the proposed post tax revenue model (PTRM) to reflect the allowances we considered appropriate, but otherwise using the parameters as previously determined by the AER, including the year 2 return on debt update.

3 AER assessment

3.1 Trigger event

In its revised revenue proposal, submitted to the AER on 6 January 2016, Powercor proposed a three element trigger for the Bushfire Mitigation contingent project 1. In our final decision on Powercor's 2016-2020 revenue determination published 26 May 2016 we approved the Bushfire Mitigation contingent project 1 as a contingent project.

We determined the trigger event for Bushfire Mitigation Contingent Project 1 to be:[46]

> *In circumstances where a new or changed regulatory obligation or requirement (within the meaning given to that term by section 2D of the National Electricity Law) ("relevant regulatory obligation or requirement") in respect of earth fault standards and/or standards for asset construction and replacement in a prescribed area of the State is imposed on Powercor during the 2016–20 regulatory control period, the trigger event in respect of bushfire mitigation contingent project 1 occurs when all of the following occur:*
>
> > *(i) Powercor has identified the proposed capital works forming a part of the project, which must relate to earth fault standards and/or standards for asset construction and replacement in a prescribed area of the State and which are required for complying with the relevant regulatory obligation or requirement. The proposed capital works must be listed for commencement in the 2016–20 regulatory control period in regulations or legislation, or in a project plan or bushfire mitigation plan[47], accepted or provisionally accepted or determined by Energy Safe Victoria;*
> >
> > *(ii) for each of the proposed capital works forming a part of the project Powercor has completed a forecast of capital expenditure required for complying with the relevant regulatory obligation or requirement;*
> >
> > *(iii) for each of the proposed capital works forming a part of the project that relate to earth fault standards, Powercor has completed a project scope which identifies the scope of the work and proposed costing.*

We determined on 28 April 2017 the trigger event was satisfied as each of the above events had occurred and a compliant application had been lodged for consideration

3.1.1 Extension of time limit

The AER published the application for public comment on 4 April 2017. We identified that the issues involved in assessing this application were difficult or complex and required further consideration. Accordingly, we issued a notice to Powercor on 28 April 2017 advising that the AER would extend the time limit to make this decision to 21 August 2017.[48]

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46 AER, *Final decision, Powercor distribution determination 2016 to 2020, Attachment 6 – Capital expenditure, May 2016*, p. 6–144.

47 Powercor *Bushfire Mitigation Plan March* 2017

48 AER Extension of time limit under NER clause 6.6A.2(j)

3.2 Expenditure threshold

The NER currently stipulates the capital expenditure threshold for a contingent project is the proposed capital expenditure:[49]

> *exceeds either $30 million or 5% of the value of the maximum allowed revenue for the relevant Distribution Network Service Provider for the first year of the relevant regulatory control period, whichever is the larger amount*

3.2.1 AER view

The Powercor application is for $91 million ($nominal) capital cost, which exceeds $30 million. Five per cent of Powercor's first year revenue is $31.1 million ($nominal). As the capital expenditure threshold has been met under the second limb of the rule, we agree the threshold has been met.

3.3 Technical considerations

3.3.1 Technical standards in jurisdictional legislation

Powercor is required to comply with the VEDC and also, all applicable Victorian electrical safety regulations arising out of the BMR.[50] Powercor has developed a revised BMP[51] which has been approved by the ESV. The BMP contains the timetable for completion of tranche 1. Under Victorian electrical safety regulations, this is a further obligation which AusNet Services must fulfil.

3.3.1.1 AER view

In 2015 the Victorian Government introduced the BMR. The BMR specify a performance regime for cutting power to a fault in a high voltage line in designated high fire risk zones of the State. A new device – a REFCL[52] device – is the only equipment currently capable of meeting the performance requirements specified by the BMR. Therefore, Powercor needs to operate the REFCLs on its distribution networks in order to comply with the BMR.

However, operation of the REFCLs without appropriate isolation measures may result in non-compliance with the VEDC. This is because when the REFCL operates the voltages on the DNSP's network will exceed the voltage limits currently specified in table 1, of clause 4.2.2 of the VEDC. Operation of a distribution network outside the limits imposed by the VEDC is likely to cause damage to a high-voltage customer's installation.

Powercor and AusNet Services each applied for contingent project funding in accordance with their determinations.[53] They each have specific requirements included in the BMPs to install and operate REFCLs. In their applications, both DNSPs cite the prospect that financial

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49 NER clause 6.6A.2(e)

50 I.E. The *Electricity Safety (Bushfire Mitigation) Amendment Regulations*, 2016

51 Bushfire Mitigation Plans (BMPs) are separate obligations regulated by Energy Safe Victoria.

52 REFCL stands for: Rapid Earth Fault Current Limiting

53 AER, *Final decision, Powercor distribution determination 2016 to 2020, Attachment 6 – Capital expenditure*, May 2016, p. 6–144.

liability will arise for damage caused by operation of a REFCL as grounds for funding by the AER of additional works to mitigate the prospect of damage to their HV customer installations.

Table 1 of clause 4.2.2 of the VEDC specifies times and durations of the maximum overvoltage condition that must not be exceeded. For the purposes of this decision, we accept that without appropriate isolation measures when a REFCL operates it will exceed both the maximum overvoltage limit and/or the time duration specified in table 1 of clause 4.2.2 the VEDC. Although the VEDC is likely to be amended to revise table 1, the AER was advised by ESCV that amendment is unlikely in the immediate future.

Compliance with the VEDC is a condition in Powercor's distribution licence. Also, clause 4.2.7 of the VEDC provides that a DNSP must compensate any person whose property is damaged due to voltage variations outside the limits prescribed by Table 1 of clause 4.2.2. However, clause 4.2.7 should be read in conjunction with clause 16 (c) of the VEDC and any applicable guideline. Clause 16(c) of the VEDC states that a customer must take reasonable precautions to minimise the risk of loss or damage to any equipment, premises or business of the customer which may result from poor quality or reliability of electricity supply.

Given that:

1. in order to comply with its obligations under the BMR, Powercor must implement REFCL devices
2. the operation of a REFCL device without the use of isolation transformers will, from time-to-time, exceed the voltage limits set in the VEDC and therefore Powercor will be in breach of its requirements under the VEDC, and
3. operation of the REFCL outside the limits specified in the VEDC is likely to cause damage to a customer's installation, and
4. clause 4.2.7 of the VEDC (as limited by clause 16(c) and the Electricity Industry Guideline) makes a DNSP liable for damage caused by operation outside those limits

we formed a view that under the VEDC as it currently applies, in order for Powercor to comply with its obligations under the VEDC and the BMRs, it is necessary that it implement REFCL devices and isolation transformers.

We note that there is an intention that the VEDC be reviewed in 2017/2018, which may be in time for Tranches 2 and 3. However, our consideration for this tranche must be in the terms of current statutory regulations and not in anticipation of potential but undefined, future revisions.

We communicated our view to the DELWP, ESV and the two DNSPs. This led to further submissions by Powercor, AusNet Services, the Minister and ESV, which submissions and our treatment of them were discussed further in section 1.7.1.

3.3.2 REFCL performance requirements

In the wake of the tragic events of 2009's Black Saturday, the Victorian Bushfires Royal Commission published 67 recommendations[54] that were all subsequently accepted by the Victorian State Government. On 1 May 2016, the Victorian Parliament acted to carry out a number of the recommendations by passing amendments to the *Electrical Safety (Bushfire Mitigation) Regulations 2013*.[55] The amendments introduced new obligations on Victorian distribution network service providers (DNSPs) that operate in high risk bushfire areas. These obligations include:

- each polyphase electric line originating from a selected zone substation must have the required capacity (discussed below)
- testing for the required capacity must be undertaken before the specified bushfire risk period each year and a report detailing the results of testing submitted to ESV
- each new or replaced line with a nominal voltage between 1 kV and 22 kV must be covered or undergrounded from 1 May 2016
- each Single Wire Earth Return (SWER) line must have an Automatic Circuit Recloser (ACR) installed by 1 May 2023

Schedule 2 of the *Electrical Safety (Bushfire Mitigation) Regulations 2013* lists 45 *selected zone substations* and assigns a point value to each one based on the level of bushfire risk. Victorian DNSPs must meet the *required capacity* obligations for *selected zone substations* totalling:

- at least 30 points by 1 May 2019[56]
- at least 55 points by 1 May 2021[57] and
- any remaining *selected zone substations* by 1 May 2023.

The *required capacity* for a polyphase line originating from a *selected zone substation* is defined in the *Electrical Safety (Bushfire Mitigation) Regulations 2013*.as:

> *'…in the event of a phase-to-ground fault on a polyphase electric line, the ability—* [58]
>
> > *(a) to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for high impedance faults to 250 volts within 2 seconds; and*

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54 Victorian Bushfires Royal Commission, *Final Report* (summary), July 2010, http://www.royalcommission.vic.gov.au/finaldocuments/summary/PF/VBRC_Summary_PF.pdf

55 *Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016* (VIC), http://www.legislation.vic.gov.au/Domino/Web_Notes/LDMS/PubStatbook.nsf/93eb987ebadd283dca256e92000e4069/9CC083A75311B617CA257FA100148082/$FILE/16-032sra%20authorised.pdf

56 Or all *selected zone substations* if less than 30 points of a DNSP's substations are defined in Schedule 2.

57 Or all *selected zone substations* if less than 55 points of a DNSP's substations are defined in Schedule 2.

58 Or all *selected zone substations* if less than 55 points of a DNSP's substations are defined in Schedule 2.

(b) to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for low impedance faults to—

(i) 1900 volts within 85 milliseconds; and

(ii) 750 volts within 500 milliseconds; and

(iii) 250 volts within 2 seconds; and

(c) during diagnostic tests for high impedance faults, to limit—

(i) fault current to 0.5 amps or less; and

(ii) the thermal energy on the electric line to a maximum I^2t value of 0.10[59]

In addition, increased compliance incentives were introduced on 11 May 2017 when the Victorian State Parliament passed the *Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme) Act 2017*. The Act introduces civil penalty provisions for the new requirements on DNSPs both as a single fine for a particular contravention and additional fines for each day the contravention remains unresolved.

3.3.2.1 AER view

Having reviewed the REFCL performance characteristics, we accept the concerns expressed by Powercor in terms of the technical challenges which must be addressed to meet REFCL performance requirements. We also accept that the BMR requires compliance to a standard of performance of the REFCL device that will exceed both the maximum overvoltage limit and/or the time duration specified in table 1 of clause 4.2.2 of the VEDC. In the absence of measures to isolate HV customer's over-voltage events, which are intrinsic to REFCL operation, damage may occur to customer networks unless the customer network is upgraded to tolerate these events.

As it is mandated by the BMR, we consider it reasonable that the performance standard be achieved, notwithstanding that the operation of the devices will require additional expenditure be incurred to address the concerns which result from operation outside the technical limits imposed by the VEDC. We have taken this as our base position in reviewing the Powercor Contingent Project Application.

3.4 Capital expenditure

The following table summarises the Powercor Contingent Project Application capital expenditure requirements.

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[59] *Electricity Safety (Bushfire Mitigation) Regulations 2013* (VIC), Regulation 5 'Definitions'.

Table 3.1: Summary of total expenditure requirements million ($nominal)

Forecast expenditure	2017	2018	2019	2020
Project costs (capitalised)	50.9	40.1	-	-
Project costs (expensed)	2.2	2.2	-	-
Incremental re-balancing works	-	-	0.1	0.3
Incremental compliance testing	-	-	0.2	0.3
Incremental technical support	-	-	0.0	0.1
Total	**53.1**	**42.3**	**0.4**	**0.7**

Source: Powercor Contingent project application, REFCL program (tranche one), 28 March 2017, table 6.9, p.52.

3.4.1 Detailed analysis

Each zone substation and associated feeders present a unique capex requirement. We have considered the individual circumstances of Powercor for each of the proposed zone substations. Also, where appropriate, we compared the unit rates and volumes against external sources by seeking prices from equipment suppliers, our own consideration of likely costs and volumes for similar works elsewhere and available benchmarks for unit costs and volumes derived from our recent work reviewing the costs of other regulated DNSPs.

3.4.1.1 Zone substation Works

The following table provides the codes used by Powercor to identify zone substations, which will also be used in this document.

Table 3.2: Zone substation codes

Zone substation	Code
Camperdown	CDN
Castlemaine	CMN
Colac	CLC
Eaglehawk	EHK
Maryborough	MRO
Winchelsea	WIN

Powercor has proposed $31.24[60] million ($nominal) for zone substation works to integrate the REFCLs including:

- the REFCL components including Ground Fault Neutraliser (GFN), Arc Suppression Coil and bunding, protection and controls, inverter and enclosure,
- additional power supplies including station service transformers
- modifications to 22kV system including neutral switching bus, ac switchboards and changeover boards
- capacitor bank upgrades
- spatial accommodation issues
- hardening within the zone substation
- civil and ground works
- associated protection and control and SCADA

The proposed works are considered below. Costs discussed in this section are $2017 costs, except where noted.

In this discussion, note that the REFCL is a specific implementation by the Victorian Government of Ground Fault Neutraliser (GFN) technology, which is common in other parts of the world. The primary distinction is the addition of residual current compensation and advanced control technology to a GFN creates the very high performance REFCL. References to GFN technology in this discussion are generally interchangeable with REFCL technology, unless the context demands otherwise.

Station service transformers

Station service transformers provide power to the systems and machinery that operate within a zone substation. Powercor considers that the station service transformers in sizes between 500 kVA and 750 kVA are required to be upgraded in order to support the additional energy requirements of the new equipment. This is because when a REFCL operates, the associated inverter injects sizeable amounts of energy to counter the faulted phase.

Based on our review of the individual site requirements, we consider that at each site Powercor has adequately scoped the increased energy requirement of the additional equipment. We have reviewed the proposed equipment costs. We consider that these costs are consistent with recent cost benchmarks[61] for similar works carried out by AusNet Services and Powercor.

Therefore, we consider that these costs reasonably reflect the capital expenditure criteria (capex criteria) having regard to the expenditure that would be incurred in respect of a

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60 REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

61 Powercor and AusNet Services RIN submissions

contingent project by an efficient and prudent DNSP in the circumstances of that DNSP under the NER, clause 6.6A.2 (g)(4).

Modifications to AC boards

Powercor has proposed additional works associated with the AC boards including changeover capability based on the additional load requirements of the new REFCL equipment. We note that the Powercor approach is broadly comparable with the AusNet Services application[62] however a slightly different design approach has been taken by Powercor. We conducted a review of the proposed design to satisfy ourselves of the need for this work.

The requirement for additional works including the AC changeover board was not identified in the RIS cost estimates, however we consider that there is a technical requirement for this work, which has only became apparent after more detailed site investigations. The works to the AC changeover board are required due to the increased alternating current (AC) supply requirement increases of demanded by the REFCL installation. A number of the AC boards have increased cost requirements where there is a technical need for multiple GFNs at the one zone substation. We consider that the proposed unit rates and volumes of works associated with the AC changeover boards are reasonable. They are consistent with our benchmarks and our independent estimates of the likely scope and cost of similar works.

We therefore consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

Arc suppression coil

The arc suppression coil cost is based on quotation from the single supplier. The device is specialised item. We note that Powercor have made considerable efforts to identify alternative suppliers but none are currently available. Therefore, Powercor has endeavoured to negotiate an appropriate supply arrangement with the sole supplier to support the Contingent Project Application. We note Powercor has endeavoured to address the inherent risks associated with a single source provider of this equipment, which plays a central role in the required works.

We therefore consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

Modifications to 22kV system

Powercor include 22kV indoor switchboards (including GFN enclosures) at two zone substations CLC and WIN. The proposed costs of these 22kV indoor switchboards is $485 000 and $496 000[63] ($nominal) respectively. Powercor considers that these switchboards are required due to specific spatial and configuration requirements to accommodate multiple GFNs at these zone substations. We examined these designs and

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[62] AusNet Electricity Services Pty Ltd *Contingent Project Application Bushfire Mitigation 2017*

[63] REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

alternate technical options but did not identify a lower cost alternative with equivalent functionality. We accept the Powercor design is appropriate.

We consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred by an efficient and prudent DNSP in the circumstances of that DNSP under the NER, clause 6.6A.2 (g)(4).

Capacitor banks

Capacitive balancing is a critical technical issue is ensuring a REFCL can operate as intended. This cost item was set out in the RIS and included in the AER's initial assessment. The Powercor 22kV Capacitor Banks have a unit cost of $320 013 ($nominal) which compares favourably with the $0-500 000 (real, $2015) [$0-523 400 ($nominal)] cost range amount estimated in the RIS[64]. We note the AusNet Services estimate[65] for 22kV Capacitor Banks and Cap Bank footings has a lower unit cost of $[C-I-C] ($, real, $2016) and $[C-I-C] (real, $ 2016) [$[C-I-C] and $[C-I-C] ($nominal)] respectively, which compares favourably with the $320 013 ($nominal) amount estimated by Powercor. We think it is unlikely that the standard would be significantly different between the two operators. The major reason for the difference is that the AusNet Services estimates are based on site specific data which indicates a low degree of initial capacitive imbalance, whereas Powercor has adopted an average cost approach for this item and must address a greater degree of initial capacitive imbalance.

We consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of that DNSP under the NER, clause 6.6A.2 (g)(4).

Circuit breakers

Powercor proposes that 22kV Circuit Breakers to be installed at zone substations CDN, CLC and EHK are required for hardening and altered switching configurations. We consider the inclusion of these components is consistent with normal distribution design standards and similar work elsewhere in the Powercor network. We acknowledge that this is a cost that a prudent operator would incur to achieve the capital expenditure objectives. We also consider that this unit cost is reasonable for an identified upgrade and is consistent with similar costs presented by AusNet Services[66].

We consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

Transformer neutral bus and switchboard

We have investigated with Powercor works for the modification of the 66/22kV transformer earthing arrangement at various sites including:

- installation of transformer neutral isolators and direct earth switches

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64 DELWP Regulatory Information Statement, *Bushfire Mitigation Regulations Amendment, Acil Allen; 2015* p69

65 AusNet Services *Contingent Project submission 2017 AST Distribution Contingent Project 1 Cost CONFIDENTIAL*

66 AusNet Services *Contingent Project submission 2017 AST Distribution Contingent Project 1 Cost CONFIDENTIAL*

- installation of 19kV surge diverters on transformer neutrals
- installation of neutral bus systems
- bus CB's
- NER terminations
- ASC terminations
- neutral VT installations.

Powercor identified that additional switching capability beyond the scope of the RIS is required to ensure its protection system continues to operate in accordance with industry standards. The Powercor application includes a separate neutral bus and additional protection and interface control systems to address this. We consider that a neutral bus is required at all GFN zone substations. A second neutral bus is required at those substations requiring a second GFN. The technical reason for this assessment is that GFNs have a specific capacitive loading capacity. As load growth on a zone substation causes the capacitive loading to exceed this level, a second (and potentially a third) neutral bus is required.

We queried the need for a transformer neutral isolator and neutral bus works. After discussion with both Powercor and AusNet Services staff, AER technical staff accept that this requirement is justified by the large increase in current flows in the neutral associated with REFCL operation.

We consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

Each neutral bus installation requires a neutral bus controller. This is a standard piece of equipment.

We therefore consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

Some zone substation works items that have been proposed by Powercor were not included in the Regulatory Information Statement [RIS][67] estimate. These include items such as the neutral bus switchboard, the GFN enclosure, REFCL backup protection and interface control systems, REFCL testing and community engagement.

We queried the requirement for a neutral bus switchboard and additional circuit breakers at WIN, EHK and CLC. Powercor advised that the zone substations are built to a 1950's design standard (referred to as "banked"), meaning that the flexibility of operation is limited. A fault within the zone substation can cause protection to operate and require manual operation to restore. Powercor argued that inclusion of the REFCL devices increases the operational

[67] DELWP *Regulatory Information Statement, Bushfire Mitigation Regulations Amendment, Acil Allen; 2015*

complexity and that manual operation would be required at CLC and EHK to change operating modes resulting in customer outages.

Powercor made a case for providing fully switched capability at WIN and the other zone substations on the basis that:

- they are introducing a new standard for operation,
- the incremental cost of additional neutral earthing CBs is small and
- the RMU approach enables modular expansion.

We note that GFNs can be paralleled and that they can be shared between transformers in a zone substation. However, an earth fault associated with a transformer needs to be cleared automatically. Otherwise, with a REFCL in operation, a cross country fault can result. Further, there is a requirement to fully switch the zone substations to enable segregation. This requires a level of flexibility not currently permitted by the “banked” configuration. We therefore accept that the Powercor design is justified.

We consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

Enclosures

On inspection of the trial site zone substations at Gisborne and Kilmore South, it was demonstrated that the GFN control system and inverter are sensitive power electronic systems. Consequently, these are items that need to be housed in an air-conditioned enclosure. Not all zone substations have the environment and space suitable for these devices. As such, we have allowed for these enclosure costs to be included where necessary.

Powercor identified a need for an additional air-conditioned control room at four zone substations at a cost of 4x$58 300 ($nominal).

We consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

Testing and commissioning

The RIS did not include REFCL testing and commissioning. This presents a significant cost item in the Powercor application; particularly associated with HV the customers' and compliance with the VEDC. This matter was identified after the RIS was published. The Powercor application allocates $3.20 million ($nominal) for testing and commissioning. This includes provision of portable diesel generators to supply HV customer sites.

We consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

3.4.1.2 Feeder works

Network balancing

Powercor has proposed $11.67[68] million ($nominal) for network balancing works to integrate the REFCLs including:

- admittance balancing units (single and three phase)
- recabling
- rephasing

Network balancing is a major component of feeder works. We have reviewed network balancing unit rates and also compared these with the RIS and AusNet Services application.

The Powercor average estimate per application of $1.95 million ($nominal) compares with AusNet average $1.87 million (real,$2016) [$1.91 million ($nominal)]. The RIS estimated network balancing at $0-340 000[69] ($, real 2015) [$0-356 000 ($nominal) per zone substation based on 0-85 phase rotations at $4 000 (real, $2015) [$4 384 ($nominal)] per zone substation. The RIS limited its balancing to phase rotations but both Powercor and AusNet Services have identified that phase rotations alone are insufficient to achieve "required capacity" and that further extensive balancing approaches are required based on recent experience.

Powercor presents an argument[70] for the increased costs in comparison to the RIS. We note the following:

- there has been new learning out of REFCL trials conducted by both DNSPs since the RIS was prepared.
- the RIS was tabled in 2015 before detailed design and site considerations were taken into account. The contingent project application was tabled in 2017.
- the RIS detailed phase rotations alone as a means of achieving balance. Subsequently is has been found that the level of leakage mitigation required to meet the Bushfire Mitigation regulations is far higher than is possible under that strategy.[71]
- Powercor has identified as necessary a combination of approaches including:
    - Installing single-phase admittance balancing units for every 300m of single-phase underground cable;
    - performing overhead re-phasing works for every 15km of single-phase overhead line

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68 REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

69 DELWP *Regulatory Impact Statement, Bushfire Mitigation Regulations Amendment, ACIL ALLEN Consulting,* Table 14, Page 69

70 Powercor Australia Ltd *Surge Arrester replacement re REFCL installation Review of Powercor surge arrester replacement strategy GHD March 2017*

71 Powercor *Contingent Project Application REFCL program: tranche one March 2017* pp41-44

- installing three-phase admittance balancing units between remote-controlled switching sections, as well as between strategically located manually-operated isolatable sections
- installing fuse savers for any fused sections with overhead line length greater than 9km and
- upgrading HV regulators to closed delta configurations with parallel control.

AER technical staff conducted site inspections at trial sites operated by AusNet Services and Powercor. We reviewed the arguments advanced for these additional activities against the field experience of operational staff at those locations. We consider the field experience justifies the combined approach as detailed above. We therefore consider the approach taken by Powercor is reasonable.

The application outlines a detailed risk and governance strategy[72]. We reviewed the approach taken by Powercor its risk and governance strategy. The AusNet Services approach is similar to the Powercor approach.[73] We consider the Powercor approach is in accordance with industry norms for complex capital works and is reasonable.

We consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

3.4.1.3 Line hardening

Line hardening works include the major activity of replacing surge arrestors and other items of Compatible Equipment.

Surge arrestors

Powercor has proposed $8,486,000[74] ($nominal) for line hardening works to integrate the REFCLs including:

- surge arrestor replacement

Powercor presented its Surge Arrestor Strategy and GHD review[75]. The strategy includes:

- testing regimes involving high voltage soaking
- sampling techniques
- replacement strategy for small and large populations

Powercor has proposed the replacement of proportion of surge arrestors[76] for Tranche 1 of the REFCL program. This equates to a unit cost of cost of $1 523 per site and $1 175

72 Powercor *Contingent Project Application REFCL program: tranche one March* 2017 p51

73 AusNet Services *REFCL Program Network Balancing Strategy 2017* p11 and 13

74 REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

75 Powercor Australia Ltd *Surge Arrester replacement re REFCL installation Review of Powercor surge arrester replacement strategy GHD March 2017*

($nominal) per unit. AusNet Services estimates in most zone substations a cost of $2 460 per site or $940 [real, $2016)[77]) [$2 517 per site or $962 ($nominal)] respectively.

The RIS presented an estimated cost of $1 000 (real, $2015) [$1 096 ($nominal)] per surge arrestor.

The Bushfire Mitigation Regulation Amendment Regulatory Information Statement[78] proposed that replacement of one in three surge arrestors would reflect an appropriate cost/risk benefit profile. This analysis was based on preliminary data for age and specification of the surge arrestor population, taking into consideration statistical failure rates. Subsequent work[79] by the an independent testing laboratory, commissioned by Powercor, identified specific makes and models of existing installed surge diverters which would require replacement.

Powercor and AusNet Services agree closely with the RIS assessment of the percentage of the surge diverter population that requires replacement. The higher percentage to be replaced (40%) is based on a detailed study of GIS data augmented by line inspections in many cases. As such, we consider the process of estimating replacement volumes is to an acceptable standard. We accept the Powercor estimate of replacement volumes.

The following historical references were compared:

Table 3.3: Surge Arrestor benchmarks

AusNet Services from 2009 Bushfire review[80].	"Planned replacement costs ranging from $1500 for surge diverters on a SWER distribution or single-phase transformer and $2000 for surge diverters on a SWER isolating or three-phase transformer" (AMS 20-67 $2009)
Powercor and CitiPower RINs (see RINs)[81].	CitiPower - $3,763 weighted unit cost ($2014). Note included HV switchgear replacement, so may not be representative. Powercor - $1,896 weighted unit cost ($2014). Note included HV switchgear replacement, so may not be representative.
AusNet Service Vic EDPR 2015[82].	$1600 per surge arrester. (Ref: Appendix 7C: Unit Rates) SAPN Bushfire mitigation program (2015)

76 Powercor *Contingent Project Application REFCL program: tranche one March 2017* p 38-40

77 AusNet Services *Contingent Project submission 2017 AST Distribution Contingent Project 1 Cost CONFIDENTIAL*

78 DELWP *Bushfire Mitigation Regulations Amendment Regulatory Information Statement 2015* p69

79 REFC.13 *Review of Powercor surge arrestor replacement strategy GHD*

80 AusNet Services from 2009 Bushfire review

81 Powercor and CitiPower RINs

82 AusNet Services Vic EDPR 2015

	"Estimated cost to replace 19kV RAGs or CLAHs with surge arrestors =about $2,007 each". "Estimated cost to replace 11kV RAGs or CLAHs with surge arrestors = about $3,755 per set of 3".

These references reflect previously accepted surge arrestor costs. On this basis, the AER accepts the additional cost per surge arrestor as proposed by Powercor in the contingent project application.

We consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

3.4.1.4 Compatible Equipment

Powercor has proposed $6.9[83] million ($nominal) for compatible equipment works to integrate the REFCLs including:

- ACR replacements and upgrades
- HV voltage regulator replacements and upgrades

Powercor has estimated the costs of ACR replacements at $25 200 ($nominal) and upgrades at $6 195 ($nominal). These compare favourably with the AusNet Services application. The RIS estimated upgrade costs at $70 000 (real, $2015) [$392 600 ($nominal)] each. This cost is lower for Powercor because the specific makes and models of equipment installed by Powercor generally have a higher capacity to tolerate overvoltage. However, as REFCL operation was not contemplated when the equipment was purchased, we recognise that the benchmark comparison, although favourable to Powercor, does not reflect a genuine cost difference.

We consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

Powercor has estimated the costs of HV regulator replacements at $150 800 ($nominal) and upgrades at $13 100 ($nominal).These compare favourably with the AusNet Services application. The RIS which estimated upgrade costs at $0-$375 000 ($real, $2015) [$73 300 ($nominal)] each.

We have considered the expenditure proposed by Powercor in relation to the HV regulators. We consider that the volume and unit rates proposed by Powercor to be reasonable.

We consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

[83] Powercor REFCL Contingent Project Application 2017 REFCL MOD.01 – Expenditure build-up model (tranche one)

3.4.1.5 Victorian Electricity Distribution Code - HV customers

Powercor has proposed $23.1[84] million ($nominal) for VEDC works to integrate the REFCLs including:

- provision of isolation transformers for each customer installation

Significant costs for the treatment of their HV customer installations were provided for in the application. Staff raised a series of information requests on the business, seeking an expanded explanation of the basis of the claimed costs and detailed breakdowns of how the estimates were derived. These explanations and detailed costs were subsequently discussed in detail with the business. They were also reviewed by AER staff and the TAG, having regard to industry norms for similar expenditure where relevant.

For the reasons set out in sections **Error! Reference source not found.** and **Error! Reference source not found.** and in this section, we have determined an alternative allowance for HV isolating transformers.

Powercor proposes to address the matter by installing isolation transformers near the customer location at a cost of $23.09 million ($nominal) [85] across 25 customers in 2MVA, 5MVA and 10MVA sizes. This transformer effectively isolates each HV customer so that the VEDC can be complied with at the customer connection point.

Powercor argues that this is the best alternative based on the following:

- there is insufficient time to resolve the matter by alternative means
- there is an insufficient relationship with the customer to identify more cost effective alternatives
- the isolation transformer is a simple and effective solution with low risk

Benchmark cost comparisons

We note that HV isolating transformers are not a standard piece of distribution equipment. In our analysis, we accept Powercor's estimate for the purchase cost of the each HV isolating transformer. The quoted numbers are consistent with similar quotes obtained by AusNet Services from another supplier. Their respective estimates are based on quotes from a reputable local suppliers. We are satisfied that this is not an item that can be readily sourced through a normal tender process, especially where overseas suppliers may become involved. The supply chain lead times and coordination requirements limit Powercor's options to local suppliers, with whom they have a strong relationship.

Powercor and AusNet Services have obtained independent prices from two independent suppliers that are comparable. This increases our comfort that the quoted prices are competitive. We also note the premium associated with the estimated prices does not appear to be large relative to standard equipment, taking into account the unique requirements of these non-standard devices.

[84] REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

[85] REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

However, we were concerned that the associated design installation, land acquisition and testing and commissioning cost estimates of Powercor were large and possibly excessive, having regard to the nature of the equipment and the matters expected to be addressed in their installation.

Although we found the material cost for the transformer itself to fall within the acceptable range for comparable equipment, we were not satisfied that the extensive design, project management, site acquisition and preparation, installation and commissioning costs as claimed by Powercor were justified.

Accordingly, we considered two arrangements involving standard distribution components which offered comparable (albeit not identical) functionality to obtain a better guide to the likely cost of support activities necessary to install a HV isolating transformer. The two configurations we considered as potential cost benchmarks were:

- the substation transformer configuration proposed by AusNet Services and,
- a HV regulating transformer

We then used these configurations to inform an alternative estimate of the cost of design, project management, site acquisition and preparation, installation and commissioning costs.

We consider the HV regulating transformer has similar connection arrangements to a HV isolating transformer. We note, however, that its internal function, secondary configuration and associated protection requirements are different. Accordingly, as we discuss in the following sections, we have adopted Powercor's estimates for the protection requirements in our alternative forecast.

Assessment of cost and feasibility

Powercor proposes an ISO kiosk style 22/22kV isolation transformer that does not require bunding, extensive security and external services. We have compared the Powercor application and the AusNet Services application on isolation transformers. We consider the indicative prices for HV isolating transformers to be comparable and reasonably consistent between the two distributors. As this is custom made equipment and is required within a mandated timeframe, we accept that the opportunity for competitive tendering is more restrictive than regular equipment purchases.

Powercor advise the 2, 5 and 10 MVA 22/22 isolation transformers are $110 446[86], $194 446 and $249 446 ($nominal) respectively. We consider these costs to be reasonable, having regard to their unique design and procurement requirements.

We have also considered the installed cost of voltage regulators at $339 940[87] ($nominal). Although functionally different to the isolation transformer, HV regulators exhibit similar design, installation, commissioning, testing and protection requirements.

We focus on the HV regulator transformer as the chief point of comparison. A HV regulator is a 22kv in / 22kv out device which has a fully installed cost of $340 000 ($nominal) for

86 Powercor Australia *Contingent Project Submission 2017 REFCL_MOD06 comp HV Cmer*

87 REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

Powercor. The HV isolating transformer is also a 22kv in / 22kv out device but is costed in excess of $823 000 ($nominal) per unit by Powercor. Functionally, what is different is the internal construction of the device and its mode of operation.

The installation cost of a voltage regulator replacement is estimated in the contingent project application to be $150 800[88] ($nominal) for labour and contracts. If an ACR is added at $41 020[89] the installation costs are $35 343 ($nominal). Similar costs for AusNet Services were $[C-I-C] (real, $2016) [$[C-I-C] ($nominal)].

We consider that given the large number of sites at which these devices are proposed to be installed, a high degree of standardisation can be achieved during the design, procurement and implementation stages. Although the initial design of the first installation may require a greater number of labour hours, we do not agree that this degree of effort will be required for every site. We note that the pad mounted transformer example demonstrates that design activities become standardised when similar works are planned and repeatedly implemented.

We have allowed for an allowance of 390 design hours to develop a design standard to be applied to all HV customer sites and divided this allowance across 23 sites. For each site we allow a further 100 hours design effort. We therefore consider that the extensive design allocation by Powercor could be reduced from 390 per site to 121 hours per site for this reason.

Similarly, live-line work, fitter and sub-tester costs as included in the Contingent Project application can be mitigated significantly when benchmarked, as these costs are inclusive in the kiosk style option and the Voltage Regulator replacement costs. We have reduced Live Line work from 177 hours to 40 hours on the basis that a strainer pole can be installed at a cost of $30 000 ($nominal) and a straightforward cutover be performed on commissioning.

Sub-tester costs of 348 hours and Fitter 196 hours, as proposed by Powercor, have been accepted. A kiosk option is self-contained and requires only minimal setup and connection work. We consider that as this type of equipment is yet to be standardised, an allowance must be made for comprehensive protection and setup costs.

With a factory built self-contained equipment item we consider construction, delivery and site control to be minor cost elements and have reduced this allocation accordingly. We also consider that civil works are reduced when installing a kiosk style arrangement as the necessary works would be limited to benching and surfacing, inclusion of an earth grid and security. We have allowed a total of $63 000 ($nominal) for this requirement.

In previous discussions with Powercor, it has been identified the customers are rural, industrial customers. We understand that available land is abundant, including within the customer boundary and that site remediation work is minimal. We accept land purchase and site remediation are applicable costs, however we have reduced the allowance for land purchase in line with Valuer-General – DELWP, *A Guide to Property Values – 2016*[90]. We accept the proposed site remediation costs.

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88 REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

89 REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

90 Valuer-General DELWP *A Guide to Property Values 2016*

Table 3.4: AER alternative cost estimate – Powercor HV isolation substations

Powercor HV Isolation Substations *($'000, nominal)*		**Proposed in application**			**AER Allowance**			**AER Allowance Comment**
Category		2MVA	5MVA	10MVA	2MVA	5MVA	10MVA	
Design	Design		68			21		Allow 100 hours design ISO kiosk is fully integrated package solution. Develop standard add full 390 hrs divided across 23 sites
Feeder Works	ACRs		51			51		Accept
	Customer connection & tie-in		95			40		Allow 40 hours Live Line work and $30k strainer pole
	Isolating transformer setup/prot		116			116		Accept
	Commissioning		25			25		Accept
	Construction delivery & site control		80			10		Security is either kiosk or fenced site, modules delivery inclusive

Contracts	Civil works (incl footings)		161			63		Allow $6K benching and surface, earthgrid $8K fence $39K foundations $10K
	Land purchase		70			23		$1400/$m^2$ is above Melb suburbs - rural industrial $67-202/$m^2$ eg Colac, Valuer General DELWP Allow $450/$m^2$
	Site remediation		46			46		Accept
	Spare ISO Transformer					13		Add Spare transformer $299K across 23 sites
	Installation cost	**$713**	**$713**	**$713**	**$408**	**$408**	**$408**	
	2 MVA ISO	110			110			Accept
	5 MVA ISO		194			194		Accept
	10 MVA ISO			249			249	Accept
HV ISO	**Total**	**$823**	**$907**	**$962**	**$518**	**$602**	**$657**	

It is noted that Powercor (and AusNet Services) have not identified a need for long HV underground runs in their estimates at any of their HV customer locations.

If the VEDC compliance issue were to be resolved, and in the absence of financial liability for the impact of a REFCL device on a HV customer installation, we note in many situations the most cost effective solution is likely to be the hardening of the HV customers' installation to an identical standard as the distribution network. This view is strongly supported by the Victorian Minister for Energy. The Victorian RIS and other work undertaken for Energy Safe Victoria also support this view. However, in this current application no legal basis has been identified for the DNSPs to undertake work on the customer installations. Consequently, neither we nor Powercor have direct cost information on this option.

Accordingly, we have based our alternative estimate on the cost of the functional equivalent to the isolating transformer. We expect if the regulatory framework is amended the DNSPs will pursue the customer hardening option at some locations, if it is more cost effective and can be addressed in the available timeframe (noting that the installations must be operational by 1 May 2019). If so, any savings in capital outlay will be substantially returned to customers in future periods through the operation of the Capital Expenditure Sharing Scheme. If material, any savings may also be passed back to customers through a negative pass-through event process in the current period.

Using the benchmarked results of $408 000 ($nominal) and incrementing for a 5MVA and 10MVA based on $110 446, $194 446 and $249 446 22/22 isolation transformer kiosks proposed by Powercor, we assess the total benchmarked cost for each to be $518 000 for the 2MVA, $602 000 for the 5MVA and $657 000 for the 10MVA size ($nominal).

Dual feeder customers

Powercor have six customers that are served by more than one feeder. Powercor proposes to provide a separate isolation transformer for each feeder. This is because they are of the view that the customer has paid for a second feeder and is entitled to a fully redundant supply[91].

The AER sought details of the affected dual feeder customers. Powercor advised there are 7 locations under consideration.

One customer with 3 feeders has a large physical distance separation between one HV feeder entry point and the other two entry points. We consider the separation justifies this feeder having a dedicated HV isolating transformer.

We further note that there are two customers with 400m and 500m distances between entry points of HV feeders to customer property. We consider the separation justifies this feeder having a dedicated HV isolating transformer.

In conjunction with Powercor, we identified one customer whose second feeder connection had been decommissioned. Powercor acknowledged the error and amended their application. We therefore reduced the number of dual feeders for further consideration to three, the fourth being associated with the decommissioned feeder.

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[91] Email from Powercor *dated 19/7/2017 RE: Powercor REFCL Contingent Project Questions #3.1*

We asked Powercor to consider the option of installing a single isolation transformer instead of two separate transformers at a dual feeder customer site.[92] Powercor responded[93] that their connection agreements include terms and conditions of supply which must be negotiated. Any change to the customer supply must be consistent with the objectives set out in the NER that require forecasts to include expenditure to maintain the quality, reliability and security of supply.[94]

We understand their argument to be that:

- where there are two feeders these must be fully segregated and,
- if an isolation transformer is to be added, then there must be one for each feeder to maintain segregation.

We have considered these arguments but we are not convinced that providing two transformers on separate feeders is prudent and efficient. We consider the following points to be relevant to this issue:

- distribution system power transformers including the isolation transformer that is being proposed have one failure in 20095 transformers in any year of operation, which is an extremely low failure rate.
- maintenance of the isolation transformers is of a low frequency and can be carried out in winter, outside of the bushfire season.
- the REFCL implementation introduces new capabilities for the existing supplies which have been justified by Powercor and AusNet Services. The zone substations from which the dual supplies are sourced will be upgraded to full switchability to enable bus segregation and automatic reconfiguration to enable full REFCL capability. The zone substations themselves are presently subject to a reliability level for faults within their perimeter which will be enhanced with full switchability.
    - Customers with dual supplies will benefit from these reliability improvements as the reserve feeders are sourced from a separate bus/transformer combination within the zone substation which will have fully automatic remote configurability.
- installing a single isolation transformer simplifies the installation as well as saves cost. This, by definition reduces the completion risk of the project.
- the obligation on a DNSP is to maintain reliability. As automation and REFCL operation will enhance reliability on each feeder, we consider these factors offset any diminution of reliability associated with a single isolating transformer.

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92 Email from AER to Powercor *dated 14/7/2017 RE: Powercor REFCL Contingent Project Questions #3.1*

93 Email from Powercor *dated 19/7/2017 RE: Powercor REFCL Contingent Project Questions #3.1*

94 Email from Powercor *dated 19/7/2017 RE: Powercor REFCL Contingent Project Questions #3.1*

95 Roos, Fredrik, and Sture Lindahl. *"Distribution system component failure rates and repair times–an overview." Nordic distribution and asset management conference. 2004*

- to minimise service outages should a HV isolating transformer fail, a spare 10MVA transformer should be held in store. We consider that this spare would be beneficial to support all HV customers, including single feeder customers across the three tranches.

- a modern distribution transformer is highly reliable but the provision of a spare enables rotation for maintenance and works in the unlikely event of a HV isolating transformer failure. The cost of a spare 10MVA unit has been allocated across 23 sites.

We do not accept that the customer installation has been compromised. A customer can have a switching arrangement that provides the flexibility of a reserve feeder with both feeders able to switch through a single isolation transformer. The ACRs or circuit breakers can be coordinated to provide rapid changeover. A bypass arrangement can be installed to enable operation while a spare isolation transformer is swapped over. We have allowed for an ACR to be installed on each affected reserve feeder to enable changeover.

The occurrence of an isolation transformer failure event or an unplanned or planned maintenance requirement is unlikely to coincide with a Total Fire Ban Day. If the transformer fails on a Total Fire Ban day, for the DNSP safety obligation to be met, the HV isolation transformer can be switched out and, if necessary, the site can be supported by diesel generator.

In the event of an isolation transformer fault or when maintenance is required:

- the REFCL can be disabled for the duration of the works.

- the isolation transformer can be isolated and bypassed by a switch.

- a single isolation transformer spare of nominally, 10MVA size can be purchased in advance and held in store to provide a spare for all of the HV customers.

    - The spare can be taken to site and replaced in a short period of time using the existing foundations and connections.

    - Allocation will be made for a spare in the amount of $299K ($nominal) and can be shared between all affected Powercor HV customers

- installing a single isolation transformer simplifies the installation as well as saves cost. This, by definition, reduces the completion risk of the project.

AER view - HV isolation transformer cost

We consider the proposed HV isolation transformer costs do not satisfy the capex criteria as we are not satisfied that the costs reasonably reflect prudent and efficient costs. We consider that the comparative analysis, benchmarking and technical alternatives discussed above present significant cost savings. Therefore, after careful consideration of the information provided by Powercor in support of a capital expenditure allocation of $23.1 million ($nominal) across 27 sites, 25 customers and 2 for increased capacitance at WIN for VEDC works to integrate the REFCLs , we consider that a more reasonable allocation is $12.9 million ($nominal) across 23 customers. Our alternative allowance is based on reduction of 4 isolation transformers on reserve feeders and a benchmarked cost of each to be $518 000 ($nominal) for the 2MVA, $602 000 ($nominal) for the 5MVA and $657 000 ($nominal) for the 10MVA size.

Table 3.5: AER alternative cost estimate – Powercor ($'000, nominal)

Powercor HV isolation transformers application ***($'000, nominal)***				**Benchmark Allowance**		**Allowance after reduction of dual transformers**			
Size	Application Estimated Unit Price	Number of ISO proposed	Application Estimate	AER Allowance unit price	AER Allowance	Eliminate second HV ISO	Number of ISO allowed	Add ACR	AER Allowance
2 MVA	823	18	14 814	518	9 324	-4	14	153	7 405
5 MVA	907	7	6 349	602	4 314	0	7		4 214
10MVA	962	2	1 924	657	1 314	0	2		1 314
Total		**27**	**23 087**		**14 852**		**23**		**12 933**

3.4.2 Other capital expenditure

Powercor has proposed $5.4 million ($nominal) for contracts to integrate the REFCLs including:

- traffic control
- line survey
- civil works
- mobilisation and demobilisation

We visited sites at GSB and KMS to discuss the other capital expenditure items associated with REFCL works. We note there are proportionally more extensive works at CDN, CLC, WIN and EHK zone substations. These require modifications that are dealt with in section 3.4.1.1 of this document.

We have reviewed these costs and they generally compare reasonably with similar estimates in the AusNet Services application on a site average basis. Powercor ($nominal) $905 000 and AusNet Services (real, $2016) $703 000 [$719 000 ($nominal)]. We note that these cannot be compared directly as Powercor and AusNet Services have allocated some of the components in different sections. Taking into account the higher traffic management costs expected at a number of Powercor sites, we consider this cost to be reasonable.

We consider that these costs reasonably reflect the capex criteria having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

3.5 Operating expenditure (opex)

3.5.1 Forecast

Table 3.6: Breakdown of Project Management Office (PMO) costs[96]

PMO (activity based)	Total cost ($'000, $nominal)	Comments
Change management and training	500	Full-day staff training, including course facilitation/materials
Customer communications	400	Two outage notices per customer, plus local media notices
Customer management	251	0.8 FTE at $150k p.a.
Regulatory and compliance	338	Contingent project development (incremental) and RIT-D
Technical support	450	1.5 FTE at 150k p.a. (during construction)
Network control	900	1.5 FTE at $150k p.a. (during construction)
Project planning and governance	200	Senior management oversight (incremental)
Project planning and governance	938	3.1 FTE at $150k p.a
Fleet resources	385	Incremental fleet overhead applied to internal labour
Total (excl escalation)	**4 362**	

Table 3.7: Opex cost breakdown[97]

Opex	Total cost ($'000, nominal pa)
Incremental technical support	90
Incremental re-balancing works	172.5

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96 Powercor *PAL Response to AER questions (10 May 2017)*

97 REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

Incremental re-balancing works (per feeder cost)	3
Incremental compliance testing (per feeder cost)	9.2

Table 3.8: Feeder count

Zone substation	Number of feeders
Camperdown	5
Colac	7
Castlemaine	5
Maryborough	6
Winchelsea	3
Eaglehawk	9
Total	**34**

Source: Powercor Contingent project application, REFCL program (tranche one), 28 March 2017, Expenditure build-up model.

3.5.2 Analysis

Annual testing and network balancing costs rise to provide a small team reflecting Powercor's strategy to test each feeder each year and address the ongoing balancing requirement. The activities are at an early experience stage. The costs are consistent with the capex components of the application. These costs can be reviewed at the next regulatory reset.

We consider that these costs reasonably reflect the operating expenditure (opex) criteria, having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

The first part of Powercor's opex application is a PMO activity based expenditure. It includes incremental resources and implementation expenditures on:

- change management and training
- customer communications
- customer management
- regulatory and compliance
- technical support

- network control
- project planning and governance
- fleet resources

Powercor argues that the development and operation of a resonant network fundamentally changes how parts of the network operate[98]. They include discussion of how the organisation needs training and development to transition to new operational processes which impact documentation, IT systems, maintenance and planning. The application stresses the short timeframe and the relatively large learning requirement in order to manage a program that has a degree of uncertainty. Significant customer contact and management will be required during the extensive testing program. Regulatory and compliance issues include further contingent project development and RIT-D processes.

Powercor demonstrates a requirement for technical support and network control resources during construction and incremental management and fleet management resources to cover the additional capital works and operations.

The RIS has not identified community engagement. Powercor has allocated funds for this purpose. We consider this allocation reasonable on the basis that:

- it is consistent with AER's broader expectations for DNSPs.
- there may be customer impacts (outages) from the commissioning and insulation testing
- the Black Saturday fires caused considerable loss of life and property. There is an expectation in the community that active engagement will be maintained.

However, it needs to be emphasised that DNSPs already have community engagement programs that they can leverage off. This means that the costs should be incremental to existing activities, not a new/standalone activity.

We consider that these costs reasonably reflect the opex criteria, having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of the DNSP under the NER, clause 6.6A.2 (g)(4).

Powercor includes in its application a proportionate operational expenditure for the following:

- incremental technical support – per annum
- incremental rebalancing works – per annum
- incremental rebalancing works – per annum feeder cost
- incremental compliance testing – per annum per feeder cost

98 Powercor *Contingent Project Application REFCL program: tranche one March 2017* p 51

We reviewed these allocations against the RIS[99] and the AusNet Services Contingent Project application.[100] We consider these costs as reasonable. We note that both Powercor and AusNet Services will be compliance testing each feeder each year and that the increased rebalancing workload is necessary to meet the required capacity specified as a legal requirement under the Bushfire Mitigation Amendment Regulations 2016.[101]

We consider that these costs reasonably reflect the opex criteria, having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of that DNSP under the NER, clause 6.6A.2 (g)(4).

3.5.3 Comparison of Powercor and AusNet Services PMO cost treatment.

Analysis was performed on PMO costs. The comparison between Powercor and AusNet Services reveals a different Cost Allocation Methodology[102] [103] approach is taken by each. The total operational expenditure for AusNet Services is $2.79 million (real, $2016) [$2.86 million ($nominal)] and does not include PMO costs as an expense. For Powercor it is $5.21 million ($nominal) including PMO costs as an expense.

AusNet Services proposes to capitalise $4.93 million (real, $2016) [$5.04 ($nominal)] for the project. Thus, the respective total PMO costs of AusNet Services and Powercor are $7.72 million (real, $2016) [$7.90 ($nominal)] and $5.21 million ($nominal).

Table 3.9: PMO cost treatment comparison

Comparison	AusNet Services ($'000, real 2016) / ($'000, nominal)	Powercor ($'000, nominal)
Opex	2 792 / 2 857	5 209
Capex	4 926 / 5 040	-
5 year total	7 718 / 7 897	5 209
Total per zone substation	**858 / 878**	**868**

Source: AusNet Services Contingent project application, REFCL program (tranche one), 31 March 2017, Total Cost Model; Powercor Contingent project application, REFCL program (tranche one), 28 March 2017, Expenditure build-up model.

On an average total per zone substation, the result is AusNet Services $858 000 (real, $2016) [$877 900 ($nominal)] and Powercor $868 000 ($nominal) respectively. The AusNet Services figure is within 1% of Powercor. We conclude the respective accounting treatments

99 DELWP *Regulatory Information Statement, Bushfire Mitigation Regulations Amendment, Acil Allen; 2015*

100 AusNet Electricity Services Pty Ltd *Contingent Project Application Bushfire Mitigation 2017*

101 Electricity Safety *(Bushfire Mitigation) Amendment Regulations 2016*

102 Cost Allocation Methodology AusNet Services

103 Cost Allocation Methodology Powercor

are reasonable, having regard to the approved Cost Allocation Methodologies. The outcomes for each business are similar over the project implementation phase.

We consider that these costs reasonably reflect the opex criteria, having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP in the circumstances of that DNSP under the NER, clause 6.6A.2 (g)(4).

3.6 STPIS[104] impact

Powercor advise that the REFCL commissioning is not required to have REFCLS operational and meeting required capacity until April 2019. Powercor advise that they believe there will be a decline in STPIS performance under REFCL operation. Powercor note in their Contingent Project application[105] that reliability impacts depend on operating mode.

> *…the magnitude of any reliability impact is uncertain, as we have limited experience installing and operating REFCLs in our network, and international experience of using REFCLs has not focused on operating modes…*
>
> *…aimed at reducing bushfire starts; and any reliability impacts are dependent on our operating mode, and this mode may change prior to the commissioning of our tranche one REFCLs (e.g. as our experience with operating REFCLs grows, ESV may require our operating mode be expanded beyond TFB days)…*
>
> *We expect to further engage with stakeholders on this issue as part of developing our regulatory proposal for the 2021–2025 regulatory control period (when greater certainty is available regarding any reliability impacts).*

We acknowledge Powercor's points but we also note the view of Victorian Government stated in the RIS that there will be a significant improvement in the duration of sustained outages for phase to ground faults when the technology is fully deployed. The actual impact on STPIS of REFCL operation is currently unknown and difficult to predict. International applications of resonant earth technology were predicated on operational safety and reliability improvements. These impacts were discussed in the RIS and formed the basis of the Victorian Government's expectation of significant longer term savings offsetting the cost of the bushfire safety mitigation program.

We agree with the Victorian Government that it is reasonable to expect significant reliability improvements as REFCL operation matures and is integrated into normal distribution operation. The current STPIS will apply to the end of the current regulatory control period which ends on 31 December 2020. The targets for the current period were set in the 2016 determination and will apply until 31 December 2020.

Accordingly, the next opportunity to consider the impact on the STPIS of this technology will arise in the consideration of Powercor's next determination. We think that this is the best time to quantify STPIS impact as Powercor will have developed some experience of operating its network with REFCLs in place and the process of developing operating

[104] AER, *Electricity distribution network service providers - service target performance incentive scheme*, 2009

[105] Powercor *Contingent Project Application REFCL program: tranche one March 2017* p30

procedures will have commenced. Some early supporting data and trends will also be evident.

3.6.1 Victorian F-factor scheme

The F-factor scheme is a Victorian Government initiative designed to lower the number of fire starts by electricity distributors' networks in Victoria. It is implemented through the National Electricity (Victoria) Act 2005.

This scheme was first introduced in 2011. Based on a cost-benefit analysis, this scheme has recently been modified by the Victorian Government to focus fire start reduction effort at high fire risk locations and times, such as code red days, which are subject to the highest penalty rates.[106] The modified scheme has been operating since July 2016, and the first reports will be released by early 2018 for the 2016/17 financial year. It is therefore too early to form a view on the impact of REFCLs on the new scheme.

106 Victorian Department of Environment Land Water and Planning: *Powerline Bushfire Safety Program f-factor Incentive Scheme: Regulatory Impact Statement,* August 2016.

4 AER's calculation of the annual revenue requirement

4.1 Capital expenditure

Powercor proposed $95.4 million ($nominal) capital expenditure to provide for REFCL installation and supporting works for six zone substations in Tranche 1 of the REFCL program.[107] Powercor provided supporting evidence and detailed cost estimates to make the Contingent Project Application.[108] These costs have not been included in the 2016-20 Distribution Determination given that these assets were not part of the planned replacement program for that period.

We have reduced the allocation for HV customer isolation transformers by $10.2 million ($nominal), as set out in section 3.4.1.5.

Our allocation is determined to be $85.2 million ($nominal) for capital expenditure.

As set out in the next section, to adjust the capex amounts sought by Powercor we calculated the adjustment to the inputs into the post-tax revenue model in real, 2015 dollars.

4.2 Operating expenditure

Powercor proposed $5.68 million ($nominal) operating expenditure to provide for REFCL installation and supporting works for six zone substations in Tranche 1 of the REFCL program.[109] Powercor provided supporting evidence and detailed cost estimates to make the Contingent Project Application.[110] These costs have not been included in the 2015-20 Distribution Determination given that these assets were not part of the planned replacement program for that period.

As set out in the next section, to adjust the opex amounts sought by Powercor we calculated the adjustment to the inputs into the post-tax revenue model in real, 2015 dollars.

4.3 Time cost of money

Clause 6A.2(b)(4)(iii) of the NER requires us to take into account the time cost of money based on the rate of return for the provider. In calculating the total allocated amount, we have made an allowance for this. The time cost of money has been based on the most recent rate of return for Powercor, as set out in our 2016–20 Final Decision.[111] The exception is that we update the values for x factor and return on debt in year 2, under the trailing average methodology, which now applies. The smoothed revenue is then calculated by adjusting the X factors to maintain final year revenue within 3.0% of the target value.

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107 REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

108 REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

109 REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

110 REFCL_MOD.01 Powercor, *Expenditure build-up model (tranche one), March 2017*

111 AER, *Final decision, Powercor distribution determination 2016 to 2020*

4.4 Calculation of revenue requirement

Table 4.1: AER Allowance: Powercor Contingent Project Revenue Requirement, 2016-2020 million ($nominal)

	2016	2017	2018	2019	2020
Return on Capital	0.0	0.0	2.8	4.9	4.7
Return on Capital (regulatory depreciation)	0.0	0.0	2.3	3.2	3.4
Operating Expenditure	0.0	2.2	2.3	0.4	0.8
Revenue Adjustments	0.0	0.0	0.0	0.0	0.0
Net Tax Allowance	0.0	0.0	0.3	0.3	0.4
Annual Revenue Requirement (unsmoothed)	**0.0**	**2.2**	**7.8**	**8.8**	**9.2**
Annual Revenue Requirement (smoothed)	**0.0**	**0.0**	**7.0**	**10.5**	**11.0**
% change	0.00%	0.00%	1.13%	1.63%	1.63%
X Factors	7.80%	4.68%	-1.13%	-1.80%	-2.60%

For this contingent project, revenue is determined by allocating the incremental opex to opex and the incremental capex amount to distribution services in the post-tax revenue model. The PTRM is updated applying the same WACC parameters as were used in the determination, including the return on debt adjustment noted above.

5 AER determination

5.1 AER determination

On 21 August 2017, the AER Board determined that the Powercor application for contingent project funding was approved but with modifications to the amounts sought in the proposal lodged on 28 March 2017. Powercor submitted their application in $nominal terms. We have used “real, $2015” as the basis for presenting the calculations of incremental capital and operating expenditure in each remaining year of the regulatory control period. This is because the Post-Tax Revenue Model calculation is expressed in real, $2015.

In accordance with clause 6.6A.2(e)(1) of the NER we have determined:

- The amount of capital and incremental operating expenditure, for each remaining year of the regulatory control period that we consider is reasonably required for the purpose of undertaking the contingent project is:[112]

Table 5.1 - Capital and incremental operating expenditure (real, $2015)

	2016	2017	2018	2019	2020
Incremental capital expenditure	0.0	43.4	33.9	0.0	0.0
Incremental operating expenditure	0.0	2.11	2.11	0.33	0.67

- The total capital expenditure we consider is reasonably required for the purpose of undertaking the contingent project is $77.3 million (real, $2015).[113]
- The contingent project has commenced and the likely completion date is 30 April 2019.[114]
- On the basis of the capital and incremental operating expenditure stated in Table 5.1 above, and otherwise in accordance with clause 6.6A.2(b)(4),[115] we have calculated the incremental revenue which is likely to be required by Powercor for each remaining regulatory year as a result of the contingent project being undertaken to be:[116]

Table 5.2 – Incremental revenue calculation and x-factors ($nominal)

	2016	2017	2018	2019	2020
Return on Capital	0.0	0.0	2.8	4.9	4.7
Return on Capital (regulatory depreciation)	0.0	0.0	2.3	3.2	3.4
Operating Expenditure	0.0	2.2	2.3	0.4	0.8
Revenue Adjustments	0.0	0.0	0.0	0.0	0.0

112 NER clause 6.6A.2(e)(1)(i).

113 NER clause 6.6A.2(e)(1)(ii).

114 NER clause 6.6A.2(e)(1)(iii).

115 NER clause 6.6A.2(e)(2).

116 NER clause 6.6A.2(e)(1)(iv).

Net Tax Allowance	0.0	0.0	0.3	0.3	0.4
Incremental Annual Revenue Requirement (unsmoothed)	**0.0**	**2.2**	**7.8**	**8.8**	**9.2**
Incremental Annual Revenue Requirement (smoothed)	**0.0**	**0.0**	**7.0**	**10.5**	**11.0**
% change	0.00%	0.00%	1.13%	1.63%	1.63%

In accordance with clause 6.6A.2(h), we have used the capital expenditure and incremental operating expenditure determined in accordance with clause 6.6A.2(e)(1)(i) to amend the post-tax revenue model to determine the effect of any resultant increase in forecast capital and operating expenditure on:

(i) the annual revenue requirement for each regulatory year in the remainder of the regulatory control period and

(ii) the X factor for each regulatory year in the remainder of the regulatory control period.[117]

We determine the effect to be:

Table 5.3 – Annual revenue requirement and x-factors ($nominal)

	2016	2017	2018	2019	2020
Annual Revenue Requirement (unsmoothed)	**587.23**	**590.11**	**637.45**	**684.43**	**705.70**
Annual Revenue Requirement (smoothed)	**621.77**	**606.45**	**627.55**	**653.69**	**686.26**
X Factors	7.80%	4.68%	-1.13%	-1.80%	-2.60%

We have determined the approved incremental contingent project unsmoothed revenue amount to be $28.1 million ($nominal). This is the amount that Powercor will recover from customers over the three years commencing 1 January 2018. This is different from the building block amount of $39.1 million ($nominal) proposed by Powercor.

We further determine the smoothed annual revenue requirement should be adjusted to $3 195.7 total million ($nominal) based on the revenue requirements and X factors set out in Table 5.3. This corresponds to a total unsmoothed annual revenue requirement of $3 204.9 million ($nominal).

We have not amended the roll-forward model.

This corresponds to an increase of 1.13% on average distribution network prices in 2018 and 1.63% in each of 2019 and 2020.

117 NER clause 6.6A.2(h)(3).

Appendix A - List of stakeholder submissions

Submission from	Date
Victorian Minister for Energy, Environment and Climate Change	8 May 2017
Late submissions:	
Victorian Minister for Energy, Environment and Climate Change	27 July 2017
Powercor	1 August 2017
Department of Environment, Land Water and Planning	15 August 2017
Victorian Minister for Energy, Environment and Climate Change	17 August 2017
AusNet Services	18 August 2017
Powercor	18 August 2017