FINAL Decision
Powercor Australia
Contingent Project

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

31 August 2018

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Contents

Shortened forms

Shortened form	Extended form
ACR	Automatic Current Recloser
AER	Australian Energy Regulator
BMP	Bushfire Mitigation Plan
BMR	Electricity Safety (Bushfire Mitigation) Amendment Regulations, 2016
capex	Capital expenditure
DELWP	Department of Environment, Land, Water and Planning
DNSP	Distribution Network Service Provider
ESCV	Essential Services Commission (VIC)
ESV	Energy Safe Victoria
GFN	Ground Fault Neutraliser
HV	High voltage
LTIC	Long term interests of consumers
Minister	Victorian Minister for Energy, Environment and Climate Change
NER	National Electricity Rules
opex	Operational expenditure
PTRM	Post tax revenue model
REFCL	Rapid Earth Fault Current Limiter
RIS	Regulatory Impact Statement
STPIS	Service Target Performance Incentive Scheme
VEDC	Victorian Electricity Distribution Code

Executive summary

On 20 April 2018, Powercor submitted a contingent project application to the Australian Energy Regulator (AER) seeking an adjustment to its revenue allowance for the installation of Rapid Earth Current Fault Limiters (REFCLs) in compliance with the *Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016* (BMR) introduced by the Victorian Government. REFCLs are designed to reduce the risk of a bushfire caused by a fallen powerline.

The application seeks to recover project costs of $127.7[1] million for tranche two of the REFCL installation program. The proposed expenditure for tranche two is for:

- installation of REFCL devices at six zone substations
- replacement of equipment in the 22kV distribution network that is incompatible with REFCL operation
- management of risks with HV customer works to ensure the mandated timetable for REFCL implementation can be met.

Since publishing our final decision for tranche one of the project, the Essential Services Commission Victoria (ESCV) completed its review of the voltage standards in the Victorian Electricity Distribution Code (VEDC). Of particular relevance to this decision, the revised VEDC that came into effect on 20 August 2018, identifies HV customers as being responsible for ensuring their electrical assets are able to withstand higher voltages occurring during REFCL operation.[2]

Our determination is that Powercor's revenue allowance should be amended to enable compliance with the amended BMRs. The applications were submitted before the VEDC was revised and included costs for alternations to affected HV customer networks. In recognition of the transfer of responsibility for protecting HV customer networks to the customers under the revised VEDC, we have reduced the project costs by $17.2 million for capex and $1.0 million for opex.

Powercor modified its application to exclude costs of HV customer isolation. However, it included a claim for costs incurred to integrate modified customer installations with its networks. We consider this reasonable for the following reasons.

Powercor must roll out the REFCL installations according to a mandated timetable. However, there is no equivalent obligation on existing HV customers. Therefore, there is a risk that REFCLs may not be able to be commissioned as required by the mandatory timetable if customer networks are not upgraded in time. To ensure the mandated timetable for REFCL implementation by the DNSPs is met, we consider it prudent for Powercor to implement low cost measures to manage the risk that HV customers are not ready in time.

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1 Powercor: *Contingent Project Application, REFCL program: tranche two*, table 7.11. $127.7 million capital costs and $5.3 million in related overheads, which are expensed. Other operating costs are $0.5 million.

All dollar amounts in this document are in real, $2015 in line with the Powercor distribution determination unless otherwise stated.

2 ESCV: *Electricity Distribution Code version 9A*, 20 August 2018, p. 12.

We note Powercor will not incur this cost for new connections because they will be designed to comply with the new VEDC voltage standards.

Compared to Powercor's initial application for tranche two, this change in the VEDC has contributed to reducing costs and therefore revenue allowance to be recovered from customers. We also have incentives in place for Powercor to outperform the benchmark allowances we set, including those allowed under this application.[3] 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.

Powercor also sought to recover expected operating expenditure of $5.8 million[4] between 2017 and 2020.

Our determination is that Powercor can now recover the efficient cost of the tranche two 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 $30.6 million ($nominal). This will increase distribution network prices on average by 2.15% 2018 and by 2.47% in 2020.

In making our determinations 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 is 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 which also avoids fire starts from falling or damaged assets. The allowance we have provided for in this decision will enable Powercor to meet these objectives while also ensuring the costs incurred are prudent and efficient in the LTIC.

Contingent project trigger event

Our distribution determination for Powercor's 2016-2020 regulatory control period included a trigger for 'Bushfire Mitigation Contingent Project 2' (tranche two of REFCL deployment) once the amended BMR came into effect.[5] To be eligible to seek approval for 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 has been satisfied.

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3 AER: *Final Decision, Powercor distribution determination 2016 to 2020*.

4 Powercor: *REFCL Contingent project application (tranche two),* April 2018, p. 58,Table 7.11.

5 AER: *Final Decision, Powercor distribution determination 2016 to 2020*, Overview, p. 57.

Extension of time

Powercor submitted its application for tranche two on 20 April 2018. On review we identified that the issues involved in assessing the application were difficult and complex and required further consideration. Accordingly, we issued a notice to Powercor on 4 May 2018 advising that we would extend the time limit to make this decision to 10 September 2018.[6]

Assessment approach

We detail our assessment approach in section 2. In summary, in reaching our decision we relied on the following information:[7]

- Powercor's application
- submissions received from the Victorian State Government, Groundline Engineering and Powercor 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 ESCV
- our records of a workshop held by ESCV on proposed changes to the VEDC
- submissions to the revised VEDC
- the revised VEDC effective 20 August 2018.

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 two contingent project should be approved, subject to adjustments to the capital and operating expenditure amounts as specified. We consider that:

- the project as described is consistent with the contingent project approved in the 2016-20 distribution 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 works to integrate modified HV customer installations with its networks should be provided
- the incremental operational expenditure reasonably required for the purpose of undertaking the project in each year of the regulatory period is $4.84 million in total
- the total capital expenditure reasonably required to complete the project is $110.5 million

6 NER: Clause 6.6A.1(j).

7 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

- the smoothed annual revenue requirement should be adjusted to $3.216 billion total ($nominal) based on an unsmoothed annual revenue requirement of $3.225 billion ($nominal) – an average increase of 2.15% and 2.47% in each of 2019 and 2020. In turn, this will increase residential electricity prices on average by 0.5% in 2019 (about $10 p.a.) and 0.6% (about $12 p.a.) in 2020 ($nominal).

- The application was made using a version of our post-tax revenue model (PTRM) that included an expected inflation input from the 2016-20 distribution determination. Subsequently, on 25 May 2018, we corrected the inflation estimate and published an amended version of the PTRM. Our decision for this contingent project uses the amended version of the PTRM which incorporates the updated inflation estimate.[8]

  - the X-factors should be adjusted as set out in section 4 to maintain the difference in the final year revenue (2020) of not more than 3%, consistent with the Powercor revenue determination

  - the project has commenced and the likely completion date is 1 May 2021.

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

[8] AER: *Letter to Powercor outlining the revocation and substitution of its distribution determination 2016-2020*.

1 Introduction

This section sets out the relevant background information to our determination. It covers whether the contingent project trigger has been met and how Powercor's revenue allowance should be amended to meet its legal and licence obligations. To arrive at our determination on the application we took into account information provided in public submissions received on the application. Three submissions were received.

1.1 What is a contingent project

Contingent projects are significant network augmentation projects that may arise during the regulatory control period but the need and or timing is uncertain. While the expenditures for such projects do not form part of our assessment of the total forecast capital expenditure that we approve in a determination, the cost of the projects may ultimately be recovered from customers in the future if:

- pre-defined conditions (trigger events) are met, where these project specific conditions are specified in the service providers' revenue determination
- the service provider submits an application for a contingent project, and we are satisfied that the pre-defined triggers have been meet
- we are satisfied that the proposed project is consistent with the contingent project specified in our revenue determination.

1.2 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.[9] Our electricity-related powers and functions are set out in the National Electricity Law (NEL) 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.[10] We examine evidence provided to determine if the mandatory pre-defined trigger event has occurred. We also examine whether the project outlined in the application is consistent with the contingent project approved in the revenue determination. We 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. If we are not satisfied that this is the case, we must determine a substitute forecast. Where we have departed 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.

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9 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 Queensland, New South Wales, the ACT, South Australia and Tasmania (electricity only) under the National Energy Retail Law.

10 NER, clause 6.6A.2(b)(3).

1.3 Powercor

Powercor is one of five 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 DNSPs 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.

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

ESV is the independent technical regulator responsible for electricity, gas and pipeline safety in Victoria. This includes administration of the *Electricity Safety Act 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 networks to comply with the new bushfire mitigation provisions must also submit annual compliance reports to the ESV regarding their progress.

The ESCV licenses energy retailers and DNSPs to operate in Victoria and administers the VEDC that all electricity DNSPs must abide by as a condition of their distribution licence. The VEDC includes provisions on quality and reliability of supply.

1.5 Bushfire mitigation reforms

In the wake of the events of 2009's Black Saturday, the Victorian Bushfires Royal Commission (VBRC) published 67 recommendations[11] all of which were subsequently accepted by the Victorian 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*.[12] The amendments introduced new technical obligations on three Victorian 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

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11 VBRC, *Final Report* (summary), July 2010, http://www.royalcommission.vic.gov.au/finaldocuments/summary/PF/VBRC_Summary_PF.pdf

12 *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

- 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[13]
- at least 55 points by 1 May 2021[14]
- 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*[15]

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

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

[13] Alternatively, DNSPs must meet this obligation for all *selected zone substations* if less than 30 points of a DNSP's substations are defined in Schedule 2.

[14] Alternatively, DNSPs must meet this obligation for all *selected zone substations* if less than 55 points of a DNSP's substations are defined in Schedule 2.

[15] *Electricity Safety (Bushfire Mitigation) Regulations 2013* (VIC), Definitions.

On 17 November 2015, a Regulatory Impact Statement (RIS) on the *Electricity Safety (Bushfire Mitigation) Amendment Regulations* (BMR) was released by the Victorian Department of Economic Development, Jobs, Transport and Resources.[16]

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 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. The RIS stated that these costs would be incurred by HV customers. However, in tranche one of the bushfire mitigation contingent project, we found that the effect of the VEDC as it operated at the time was to require the DNSPs to incur this cost.

1.5.2 Previous AER assessments relating to this application

In Powercor's 2016-2020 distribution determination we included funding for REFCL installation trials at Woodend and Gisborne zone substations.[17] Powercor was obligated to undertake these trials, which formed part of its Bushfire Mitigation Plan (BMP)[18].

In the 2016-2020 distribution determination for Powercor, trigger events were defined for three successive bushfire mitigation contingent projects during the 2016-2020 regulatory period.[19] These contingent projects are specifically for expenses incurred to comply with Victorian bushfire regulations that prescribe the installation of REFCLs and associated works.

1.5.3 REFCL contingent project tranche one

On 28 March 2017, Powercor submitted an application to us seeking a determination for funding for a contingent project to be approved, and its maximum allowed revenue to be adjusted in accordance with the NER, to enable it to install REFCLs at designated zone substations for tranche one of the project, as specified by the BMR. The REFCL installations identified in tranche one must be operational by 1 May 2019.

The tranche one application sought to recover project costs of $95.4 million. This included $5.7 million for operating expenditure, and capital to cover the cost of installing REFCLs at zone substations, replacing equipment in the 22kV distribution network that is incompatible with REFCL operation, and installing isolation transformers to protect HV customers' equipment from damage from increased voltages occurring during REFCL operation.

Our final decision released on 21 August 2017, approved Powercor's application for contingent project funding with modifications to the amounts sought in its application. In particular, it provided for $85.2 million in total for tranche one of the project. Taking into

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16 See: https://www.energy.vic.gov.au/safety-and-emergencies/powerline-bushfire-safety-program/electrical-safety-bushfire-mitigation-further-amendment-regulations-2016

17 AER: *Final decision, Powercor distribution determination 2016-20, Attachment 6 – Capital Expenditure*, p. 134.

18 Bushfire Mitigation Plans are separate obligations regulated by Energy Safe Victoria.

19 AER: *Final decision, Powercor distribution determination 2016-20, Attachment 6 – Capital Expenditure,* p. 144.

account the forecast capital and operating expenditures for the project, it specified a total smoothed annual revenue requirement of $3.196 billion.

1.5.4 Essential Services Commission voltage standards review

A significant matter for tranche one was the Victorian Government preference that in complying with the BMR the costs to protect HV customer networks during REFCL operation should be borne by the relevant customers. However, the voltage limits specified in the VEDC made DNSPs liable for these costs. Consequently, the ESCV undertook a review of the voltage standards in the VEDC to address this inconsistency. The review is now complete and the revised VEDC came into effect on 20 August 2018. It has a direct effect on the allowances we have determined will apply to tranche two.

REFCLs are designed to trigger when an abnormal scenario occurs on a network. For example, when a powerline falls and comes into contact with the ground, REFCLs operate to rapidly reduce the potential of an electrical spark igniting a fire by redirecting the power from the fallen line to the remaining lines. In doing so it increases the voltage levels in that part of the distribution system so that voltage levels may be outside the allowable range in the VEDC.

To accommodate the voltage variations stemming from REFCL activity the ESCV has amended the VEDC to allow for voltage variations during REFCL operation in relevant parts of the electricity distribution networks.

The revised VEDC:

- introduces voltage variation limits that apply when REFCLs operate for bushfire risk mitigation
- introduces new obligations for DNSPs to annually publish information on planned REFCL installations
- clarifies the liability of affected parties during REFCL operation, including DNSPs and high voltage (HV) customers
- introduces new definitions to support REFCL operation.

A chief consequence of allowing higher voltages during REFCL operation is that HV customers will need to adopt measures to protect their equipment from high voltage events.

During the ESCV's consultation we provided a submission supporting the proposed changes to voltage standards to the minimum extent necessary to deal with overvoltage events caused by REFCL operation mandated under the BMR. We welcomed the requirement for HV customers to modify their networks to suit REFCL operation, and the removal of phase-to-earth voltage limits when a REFCL is operating. We also supported proposed changes to address customer information, reporting and monitoring requirements.

1.6 Powercor's application

On 20 April 2018, Powercor submitted a contingent project application for funding to install REFCLs at six zone substations and for other associated works including the replacement of 7,876 surge arrestors.

The expenditure required to install REFCLs was not included in Powercor's revenue allowance for the 2016–2020 regulatory control period. Instead, the AER's final decision specified the installation of REFCLs as three consecutive contingent projects (i.e. a project whereby capital expenditure is probable in the regulatory control period, but either the cost, or the timing of the expenditure is uncertain).

Powercor has split its programme of REFCL installations across its 22 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 (see section 1.4 above). The second tranche, which is the subject of this contingent project application, is for works to be completed and operational by 1 May 2021.

We published the application for public comment on 20 April 2018. Consultation closed on 15 June 2018. We identified the issues involved appeared difficult or complex. Accordingly, we issued a notice to Powercor on 4 May 2018 advising that we would extend the time limit to make this decision by 10 September 2018.

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

- Ballarat North
- Ballarat South
- Bendigo
- Bendigo TS
- Charlton
- Geelong

The proposed total capital cost is $127.7 million for the six projects. Powercor forecast an increase in opex in the revenue requirement of $6.4 million.[20]

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

[20] Powercor: *REFCL contingent project application (tranche two),* April 2018. p.58

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

	2017	2018	2019	2020	Total
Return on capital	0.1	0.1	5.0	8.2	13.3
Return on capital (regulatory depreciation)	0.0	0.0	5.3	6.9	12.2
Operating expenditure	0.0	3.2	2.6	0.6	6.4
Net tax allowance	-0.0	-0.0	0.7	0.7	1.4
Annual revenue requirement (unsmoothed)	0.0	3.3	13.6	16.4	33.3
Expected revenue (smoothed)	0.0	0.0	16.4	17.2	33.6

Source: Powercor, *Contingent Project application, REFCL program (tranche two)*, 20 April 2018, table 1.1, p. 58.

1.7 Our consultation process

For the purpose of seeking public comment, our practice is to publish applications for a contingent project as soon as practicable after they have been received. Submissions received are considered by us before we make a decision on the application. [21]

1.7.1 Submissions

We received three written submissions and also met with DELWP who provided oral feedback on the Minister's submission. Stakeholder views and our responses are summarised below.

Groundline Engineering

Groundline Engineering (GE) questioned the use of REFCLs suggesting they are expensive and will introduce problems into the grid, being incompatible with grid infrastructure. It suggested these problems will require further expenditure to manage. GE suggested other technologies are preferable, including covered conductors, stand-alone power supplies as well as the replacement of existing aged infrastructure. It suggested the legislative instrument mandating REFCLs is flawed because it relies on outdated information, and that the AER should consider the use of other technologies which are safer and more cost effective.

The Victorian Government in its Bushfire Mitigation Regulations (BMR) mandated a "required capacity" for reduction in fault current in single phase faults. At present the only way to achieve this is by installing a REFCL.[22,23] Our role as the economic regulator is to

21 NER, clauses 6.6A.2(c) and (d) also apply.

22 Response to PBST 2011 https://www.energy.vic.gov.au/safety-and-emergencies/powerline-bushfire-safety-program/reports-and-consultation-papers/response-to-pbst

23 See the Victorian Department of Environment, Land, Water and Planning website for further information on the Bushfire mitigation regulations, https://www.energy.vic.gov.au/safety-and-emergencies/powerline-bushfire-safety-program/electrical-safety-bushfire-mitigation-further-amendment-regulations-2016.

ensure a prudent and efficient implementation of the REFCL technology as specified in the BMR.

We note the points raised in GE's submission, including suggestions for alternative technologies to reduce bushfire risk. We also note that a number of these, including covered conductor technology, replacement of aging infrastructure and vegetation management have already been adopted by the distribution businesses in response to the VBRC. However, the requirement to install REFCLs is set out in Victorian Government legislation and was seen as an important additional safeguard. As such, this is a regulatory obligation on Powercor for the purposes of the NER. Consequently, we do not have the power to substitute an alternative technology that does not comply with the requirements of the BMR.

Victorian Minister for Energy, Environment and Climate Change

The Victorian Minister for Energy, Environment and Climate Change provided a submission supporting the continued implementation of REFCLs under tranche two. The Minister identified the need to implement the installation program at a fair and reasonable cost to electricity consumers, requesting us to undertake all regulatory, technical and financial due diligence to interrogate all capital and operating expenditure claims from the DNSPs. The Minister also requested us to take into account the ESCV's revisions to the voltage standards in the VEDC in coming to our decision.

In addition, the Minister identified a number of specific concerns, two of which are relevant to Powercor, and our response is as follows:

1. that volumes of the pre-emptive replacement of older underground cable are reasonable

    We note that older underground cable types are prone to failure when REFCLs are operated. The repeated operation of a REFCL damages the insulation of underground cables. Older cable types have less residual capacity to tolerate higher voltages and are prone to early failure, leading to prolonged outages that reduce reliability. We have examined the volumes proposed by Powercor and are satisfied they are reasonable to address asset failures caused by REFCL operation.

2. the reduction in system capacitance thresholds estimated by Powercor has resulted in a requirement for multiple REFCLs at some substations. This has resulted in a significant increase in costs claimed by Powercor for tranche two compared with tranche one. The AER should carefully consider the change in capacitance levels thresholds to verify the basis for the change.

    We note the increase in the number of REFCLs required for tranche two compared with tranche one, but on examination we are satisfied this is not due to changes is capacitance thresholds. Rather, it is due to the larger physical size of the networks and greater volume of existing underground cable in networks traversing rural and peri-urban zones, resulting in higher capacitance values than those anticipated when the RIS was developed in 2015. Since the VBRC findings were published, greater use of underground cable has occurred in fire prone regions, which adds to the capacitance of many feeders that are to be served by REFCLs.

Powercor

In anticipation of changes to the VEDC which has now been finalised and came into effect on 20 August 2018,[24] Powercor suggested amendments to its tranche two application. In particular, Powercor sought the:

- removal of all HV customer isolation substation costs and distribution code variation payments from its application
- addition of costs to install ACRs at all HV customer sites
- addition of costs to install neutral displacement protection coordination equipment for generator HV customers
- addition of costs for Powercor to independently verify third party reports that HV customers are appropriately hardened or able to be isolated from Powercor's network.

As discussed in section 3.5.1, we consider it appropriate that Powercor receives costs for HV customer isolation during REFCL commissioning to ensure the mandated timetable specified in the BMR is met.

24 ESCV: *Electricity Distribution Code version 9A*, 20 August 2018.

2 Assessment approach

Our assessment of the Powercor application occurs in two phases. Firstly, we assess the application for compliance with NER clause 6.6A.2(b). Secondly, we examine the detail of the proposal for compliance with the further requirements of NER clause 6.6A.2, particularly in relation to prudent and efficient costs.

We examined Powercor's tranche two application and assessed it to be compliant under clause 6.6A.2(b) of the NER.

To complete the review of the application we:

- issued questions to Powercor and examined its responses
- conducted analysis of sub-projects identified in the application.

2.1 National Electricity Rules requirement

The NER states a contingent project application must contain the following information:[25]

(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);

(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 we must take into account:[26]

(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;

[25] NER, clause 6.6A.2(b)(3).

[26] NER, clause 6.6A.2(g).

(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.

In making this determination we 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 to Powercor's contingent project

To assess Powercor's application for a contingent project we followed the process set out in the NER clause 6.6A.2. Specifically we:

- verified that a project trigger event had occurred
- tested that the amount sought exceeded the threshold for a contingent project as set out in rule 6.6A.1(b)(iii)
- reviewed the application and public submissions.

We then investigated the following matters:

- differences between Powercor's estimates included in its application and the outturn costs for works undertaken in tranche one of the project
- differences between the Powercor and AusNet Services applications
- the technical approach proposed in the application
- VEDC compliance
- differences between REFCL driven expenditure and reliability objectives already incentivised under the STPIS program, to ensure there is no conflict between the REFCL modifications and those achieved through reliability incentives
- differences between DNSP obligations and REFCL related statutory compliance obligations

- capex vs opex balance
- costs included in the revenue determination
- treatment of depreciation
- production of estimates
- governance.

We examined these matters in correspondence with Powercor, sought further information and considered its responses. We also considered its application against the benchmark of a prudent and efficient network business.

It should be noted that although the REFCLs represent a significant part of the overall investment, it also comprises electrical components which are widely used in providing distribution services and are not new technology. Our benchmarking activity compared the following points of reference:

- Powercor tranche one decision
- Powercor tranche two application
- AusNet Services tranche one decision
- AusNet Services tranche two application
- the RIS and
- AER benchmarks for common distribution equipment for all DNSPs in Australia.[27]

We concluded that Powercor's application presented efficient expenditure with some exceptions. We also considered whether a prudent and efficient network business would have structured the project in a similar way to that proposed by Powercor, and concluded they would with some exceptions.

Powercor provided detailed cost estimates and has advised us there are no confidentiality requirements relating to the information provided. It only requested that we not identify customers. We accepted the commercial-in-confidence nature of customer information which is consistent with our confidentiality guideline.

We sought advice from internal technical experts to assist us in making this determination. They examined how estimates were constituted and identified weaknesses in Powercor's application which we addressed in our questions to Powercor.

Having determined the required capital and operating expenditure necessary to complete the project, we modified the proposed PTRM to reflect the allowances we consider appropriate. All other parameters remain unchanged.

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27 To benchmark particular components such as conductors, transformers, civil works and buildings, general electrical estimating skills using online and publicly available quantity surveying resources were also used.

3 AER assessment

3.1 Trigger event

In its revised revenue application for the 2016-202 regulatory period submitted to the AER on 6 January 2016, Powercor proposed a three element trigger for the bushfire mitigation contingent project. In our final decision on Powercor's 2016-2020 revenue determination published 26 May 2016 we approved the bushfire mitigation contingent project two as a contingent project.

The trigger event for bushfire mitigation contingent project two was described as follows:[28]

> *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 2016–2020 regulatory control period, the trigger event in respect of bushfire mitigation contingent project 2 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 2016–2020 regulatory control period in regulations or legislation, or in a project plan or bushfire mitigation plan, 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 costings; and*
>
> IV. *the AER has made a determination under clause 6.6A.2(e)(1) of the NER in respect of bushfire mitigation contingent project 1.*

We determined on 11 May 2018 the trigger had occurred and we had received a compliant application for consideration.

3.2 Extension of time limit

We published the application for public comment on 20 April 2018. We identified that the issues involved in assessing the application were difficult and complex and required additional time to consider and consult upon. Accordingly, we issued a notice to Powercor on

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

4 May 2018 advising that we would extend the time limit to make this decision to 10 September 2018.[29]

3.3 Expenditure threshold

The NER currently stipulates the capital expenditure threshold[30] for a contingent project is the proposed capital expenditure:[31]

> *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*

3.3.1 AER view

The Powercor application is for $127.7 million capital cost, which exceeds $30 million. Also, 5% of Powercor's first year revenue is $28.7 million.[32] Hence, the capital expenditure threshold has been met.

3.4 Technical considerations

3.4.1 Technical standards in jurisdictional legislation

Powercor is required to comply with the VEDC as well as all applicable Victorian electrical safety regulations arising from the BMR.[33] Powercor has developed a revised BMP which has been approved by the ESV. The BMP contains a timetable for completion of tranche two. Under Victorian electrical safety regulations, this is a further obligation which Powercor must fulfil.

3.4.2 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 in Victoria. A REFCL remains the only equipment currently capable of meeting the performance requirements specified by the BMR. Therefore, Powercor needs to operate REFCLs on its distribution network in order to comply with the BMR.

Powercor and AusNet Services each applied for contingent project funding in accordance with their determinations.[34] They each have specific requirements included in their BMPs to install and operate REFCLs.

In their tranche two applications both DNSPs cited the prospect that financial liability will arise for damage caused by the operation of a REFCL as grounds for funding of additional

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

30 NER, clause 6.6A.1(b)(iii).

31 NER, clause 6.6A.2(e).

32 Powercor: *REFCL contingent project application (tranche two),* April 2018, p. 23.

33 *Electricity Safety (Bushfire Mitigation) Amendment Regulations*, 2016.

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

works to mitigate damage to affected HV customer networks. However, the subsequent ESCV review of voltage standards in the VEDC has resulted in a transfer of responsibility to protect HV customer networks to customers. In practise, this means customers will need to meet the costs of line hardening and installing isolation transformers.

Accordingly, Powercor modified its application to exclude the costs of HV customer isolation, though it included some other HV customer related costs which are seen as transitional and designed to address other implementation risks for the DNSPs. These customer related works relate to installation of ACRs as well as sensors to detect potential cross-country faults originating at customer premises, portable generators to support HV customer load during commissioning, and the employment of an independent consultant to verify the condition of each HV customer connection prior to REFCL operation.

We note that after completion of the three REFCL tranches, the cost of the abovementioned discretionary requirements for connections will be borne by each new HV customer according to the customer connection policy which will be applied consistent with the revised VEDC. However, in relation to existing HV customers we consider it appropriate for the DNSPs to incur these transitional commissioning interface isolation costs. In particular, DNSPs are subject to a mandated timetable (with penalties attached for failure to meet the timetable) for the roll-out of REFCLs. However, there is no equivalent obligation on existing HV customers. Therefore, there is a risk that REFCLs may not be able to be commissioned as required by the mandatory timetable if customer networks are not upgraded in time. To address this, we consider it prudent for the DNSPs to incur these relatively small transitional costs to isolate these customers should their networks not be upgraded in time for REFCL commissioning, so as not to delay the role out of REFCLs according to the timetable specified in the BMR.

3.5 Capital expenditure

The following table summarises the Powercor contingent project application capital expenditure requirements.

Table 3.1: Summary of total expenditure requirements million ($m, 2015)

Forecast expenditure	2017	2018	2019	2020	Total
Project costs (capitalised)	-	74.8	52.9	-	127.7
Project costs (expensed)	-	3.0	2.3	-	5.3
Incremental re-balancing works	-	-	-	0.2	0.2
Incremental compliance testing	-	-	-	0.2	0.2
Incremental technical support	-	-	-	0.0	0.0
Total	**-**	**77.8**	**55.3**	**0.5**	**133.5**

Source: Powercor: *REFCL contingent project application (tranche two)*, 20 April 2018, table 7.12, p. 58.

In this discussion, note REFCLs require the use of Ground Fault Neutralisers (GFNs) for the specific purpose specified by the BMR. REFCLs are distinguished by the addition of residual current compensation and advanced control technology to a GFN which creates the high performance REFCL. References to GFN technology in this discussion are generally interchangeable with REFCL technology, unless the context specifies otherwise.

3.5.1 Detailed analysis

Each zone substation and associated feeders has a unique capex requirement. We have considered the individual circumstances of each zone substation in Powercor's tranche two application. Where appropriate, we compared the unit rates and volumes against external sources by seeking prices from equipment suppliers. We also considered 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.

Compared to the RIS and the tranche one application, we note that the costs per site are higher than listed in the earlier documents. Our investigation has found that a substantial contributor to this is the larger size and complexity of the networks being served in this tranche. Notably, a number of sites are a mixture of peri-urban and rural locations and this adds significantly to the technical challenges for REFCL design and installation. In turn, this has led to an increase in both the complexity of the REFCL works and the consequent costs.

Table 3.2: Zone substation codes

Zone substation	Code
Bendigo TS	BETS
Charlton	CTN
Bendigo	BGO
Ballarat South	BAS
Ballarat North	BAN
Geelong	GL

Table 3.3: REFCL and ancillary equipment costs

Zone substation	RIS[35] (real, $2015)	Power Tranche two Application[36]
Bendigo TS	$7 144 691	$13 688 972
Charlton	$7 495 514	$11 105 226
Bendigo	$5 076 497	$12 465 553
Ballarat South	$10 307 200	$22 756 974
Ballarat North	$10 337 272	$31 726 904
Geelong	$6 044 244	$17 414 215

Zone substation Works

Powercor requested $41.2[37] million for zone substation works to integrate the REFCLs including:

- The REFCL components: Ground Fault Neutraliser (GFN), Arc Suppression Coil and bunding, protection and controls, inverter and enclosures
- additional power supplies such as station service transformers
- modifications to 22kV systems 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.

35 Regulatory Impact Statement bushfire mitigation regulations amendment November 2015.

36 Powercor: *REFCL2_MOD.01 Expenditure build-up model (tranche two),* April 2018.

37 Powercor: *REFCL2_MOD.01 Expenditure build-up model (tranche two),* April 2018.

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 must 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 these costs are consistent with recent cost benchmarks[38] for similar works carried out by AusNet Services and Powercor.

Therefore, we consider these costs reasonably reflect the capital expenditure criteria (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).

Underground Cables

Underground cables replacement is a major departure from tranche one as has been noted by both Powercor[39] and AusNet Services[40] and DELWP in its submission[41].

Powercor and AusNet Services have each developed similar strategies for testing and replacement of underground cables. See Marxsen report.[42]

Powercor presented an XPLE cable technical review[43], which presents experience from tranche one and other underground cable experience. The strategy considers age and risk profile of particular cable sections. Powercor presents a cable replacements cost in tranche two of $10.1 million[44].

The average cost of underground cable testing and replacement per zone substation for Powercor in tranche two is $1.7 million, and $C-I-C million for AusNet Services. The difference between the two is driven by the variation in cable length and age which determines the extent of testing versus immediate replacement decisions. Also, AusNet Services is adopting a testing and reactive replacement strategy which has been separately allocated.

The approach is consistent with good engineering practice. We consider that the application is sufficiently rigorous in setting out grounds to support this approach. We accept that the prediction of underground cable failures in old cables resulting from unanticipated applied voltages is difficult to determine precisely. . Both Powercor and AusNet Services are

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38 Powercor and AusNet Services RIN submissions.

39 Powercor: *REFCL contingent project application (tranche two),* 20 April 2018.

40 AusNet Services: *REFCL contingent project application (tranche two),* 20 April 2018.

41 DELWP: *Letter to AER*, June 2018.

42 Marxsen: *HV customer assets and REFCL protected networks: a preliminary risk survey*, June 2017.

43 Powercor: *REFCL2.10 XLPE cable review v1.0*, April 2018.

44 Powercor: *REFCL2_MOD.01 – Expenditure build-up model (tranche two),* April 2018.

adopting similar strategies. Cable failures may lead to outages, leading to reduced reliability and inconvenience for customers. The consequences of a failure presents a considerable financial risk to the DNSP under the penalty scheme which applies. We therefore consider their proposed approaches are prudent and efficient. It is also worth noting both DNSPs experienced repeated cable failures during commissioning of tranche one.

We are of the view that the performance of tranche one and tranche two underground cables under the respective DNSPs' strategies will provide guidance for further refinement of the approach to identify cables requiring replacement in tranche three.

Altogether, we consider these costs reasonably reflect the capital expenditure criteria (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).

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. Powercor's approach is broadly comparable with AusNet Services' application[45] however, Powercor has taken a slightly different design approach. 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 become apparent after more detailed site investigations. The works associated with replacement of AC changeover boards is required because the alternating current (AC) auxiliary supply requirement dramatically increases due to the GFN installation.[46] The cost of this work will be higher than specified in the RIS at all but one zone substation because of the need for multiple GFNs at these locations.

We consider the proposed unit rates and volumes of works associated with the AC changeover boards are reasonable. They are consistent with the benchmarks and independent estimates of our internal engineering experts of the likely scope and cost of similar works. **Table 3.4** below describes tranche two sizing of GFNs.

Therefore, we consider these costs reasonably reflect 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).

GFNs and Arc suppression coils

The arc suppression coil cost is based on quotation from the single supplier. The device is specialised item. Powercor has made considerable efforts to identify alternative suppliers but none have a product that can be implemented within the tranche two mandatory timeframe. Therefore, Powercor has endeavoured to negotiate an appropriate supply arrangement with the sole supplier to support the contingent project. Powercor has endeavoured to address

45 AusNet Services: *Contingent Project Application Bushfire Mitigation 2017*

46 AusNet Services – *REFCL contingent project application (tranche two)* April 2018 p. 40.

the inherent risks associated with a single source provider of this equipment, which plays a central role in the required works. The cost per GFN has not increased.

Table 3.4 outlines the tranche two GFN sizing. We note that several of the tranche two zone substations are more complex than the tranche one zone substations. They have larger networks and therefore greater capacitance and three GFNs are required in Ballarat South and Ballarat North Zone Substations. We consider this a dominant factor in the increased cost of the tranche two projects compared with tranche one.

Powercor has reduced the design capacitive charging current to achieve required capacity to detect earth faults[47] in order to comply with the BMR[48] from 130A per GFN to 108A based on experience gained from testing in tranche one. However, in each case the more conservative threshold is immaterial to the number of GFNs to be deployed in tranche two, meaning that the actual site capacitive charging current in each case (note special case of BGO below) more than exceeds both thresholds. On this basis, we will reserve judgment on the technical argument for the lower threshold until tranche three, if the cost is material.

In lay terms this means that Powercor has adopted a lower value for a key design parameter (i.e.it has derated the REFCLs) based on experience obtained in tranche one of the program. This matter was raised in the submission from the Victorian Minister. Our subsequent investigation has found the change in the derating is not the reason for the larger number of REFCLs proposed to be deployed. Also, the number REFCLs is larger than assumed in the RIS because the capacitive charging current at many locations is higher than originally anticipated. This is due to the significant amount of underground cables used on these feeders. This effect was not allowed for in the RIS estimates. As the derating has not affected the number of units required, we have not examined the basis of the derating in detail. We will do so if it affects the number of units required in the third tranche.

We raised the issue of the conservative specification at BGO following discussion with Powercor who explained that the site's 125A of capacitive loading is very near the earlier threshold set in tranche one, of 130A. We received the following in response:

> *Growth in underground cable length on the BGO network[49] over the last 20 years has been on average 1.5km per annum. Consequently, by 1 May 2021 when BGO must achieve 'required capacity', the network capacitance for the BGO network will be in excess of 130A.*

Capacity is also required for temporary transfers from BETS and EHK.

In light of the above, we are satisfied the change in network capacitance threshold from 130A to 108A does not impact the requirement for two GFNs to be installed at BGO.

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47 Implementation & Optimisation of Resonant Networks for Victorian REFCL Applications 2018, p 15.

48 Bushfire Mitigation Amendment Regulations 2016

49 Powercor: *REFCL T2 Questions #3.0*, email, 31 July 2018.

Table 3.4: Tranche two GFN sizing

Zone substation	Code	Network Capacitance (A)	GFNs required
Bendigo TS	BETS	148	2
Charlton	CTN	93	1
Bendigo	BGO	125	2
Ballarat South	BAS	280	3
Ballarat North	BAN	292	3[50]
Geelong	GL	149	2

Source: Powercor: *REFCL contingent project application (tranche two)*, 20 April 2018.

We therefore consider 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).

Modifications to 22kV system

Powercor included a 22kV indoor switchboard at one zone substation: GL. The cost is greater than the estimated per unit cost in tranche one where two zone substations required indoor switchboards. Powercor submitted an options analysis[51] with the application, which describes the selection of the particular method and details the components and costs.

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 become apparent after more detailed site investigations. The works associated with replacement of AC changeover boards is required because the alternating current (AC) auxiliary supply requirement dramatically increases due to the GFN installation. The cost of this work will be higher than specified in the RIS at all but one zone substation because of the need for multiple GFNs at these locations.

We consider 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. **Table 3.4** above describes tranche two sizing of GFNs.

50 BAN also requires a GFN on feeder due to the length and characteristics of the feeder.

51 Powercor: *REFCL2.07 GL zone substation options analysis v1.0*, April 2018

We consider 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 factor 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 per unit costs are similar to the AusNet Services estimate[52] and fall within the $0–500 000 range estimated in the RIS.[53] We think it is unlikely that the standard would be significantly different between the two operators. The major reason for the relatively minor 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 note that there is a requirement for one capacitor bank at BAN, and two at the other Powercor tranche two sites.

We consider 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).

Transformer neutral bus and switchboard

We have investigated Powercor's proposal to modify 66/22kV transformer earthing arrangements at various sites including:

- installation of transformer neutral isolators and direct earth switches
- 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

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52 AusNet Services: *Total cost model (tranche two), CONFIDENTIAL,* April 2018.

53 DELWP: *Regulatory Impact Statement, Bushfire Mitigation Regulations Amendment, Acil Allen,* 2015, p. 69.

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 in tranche one. After discussion with both Powercor and AusNet Services, AER technical staff accept that this requirement is justified by the large increase in current flows in the neutral associated with REFCL operation. Each neutral bus installation requires a neutral bus controller, which 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 that DNSP under the NER, clause 6.6A.2(g)(4).

Other zone substation works items proposed by Powercor that were not included in the Regulatory Impact Statement [RIS][54] estimate include the neutral bus switchboard, GFN enclosure, REFCL backup protection and interface control systems, REFCL testing and community engagement.

In tranche one we queried the requirement for a neutral bus switchboard and additional circuit breakers at zone substations with one GFN. Powercor advised that the zone substations are built to a 1950's design standard (referred to as "banked"), resulting in limited operational flexibility. A fault within the zone substation can trigger protection that requires manual operation to restore. Powercor argued that inclusion of the REFCL devices increases the operational complexity and that manual operation would be required at zone substations to change operating modes resulting in customer outages.

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

- they are introducing a new standard for operation
- the incremental cost of additional neutral earthing CBs is small
- 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 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).

[54] DELWP *Regulatory Impact Statement, Bushfire Mitigation Regulations Amendment, ACIL ALLEN Consulting, 2015.*

GFN Enclosures

The cost of GFN enclosures has increased since tranche one because the previous supplier went out of business. Powercor now estimates the unit cost of GFN enclosures is $144 921[55], compared with the AusNet Services estimate[56] of $ C-I-C for a single GFN control room and $ C-I-C and $ C-I-C for a control room housing two GFNs.

Powercor proposes to install ten GFNs at five sites costing on average $72 461 per site. AusNet Services proposes to install fifteen GFNs at eight sites costing on average $ C-I-C per GFN. We acknowledge Powercor has taken a different approach in the design and layout of the GFN systems, including in its selection of indoor and outdoor systems. The Powercor concept can accommodate up to three GFNs affording economies of scale, and the AusNet Services' concept provides for single and double GFN control rooms.

We consider 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).

Spare GFN

Powercor proposes to purchase a spare GFN. In its application it advised[57]:

> *We have included within this application costs for a spare GFN to be used if another GFN fails. The long lead times for procurement of a GFN support holding a spare as part of our asset management strategy. Should a GFN fail during the testing and commissioning phase, or when in-service, then the spare can be utilised to ensure that we meet our obligations as set out in the Amended Bushfire Mitigation Regulations, and are able to continue to operate the network in a safe and reliable manner. By the end of tranche two, we will have 26 GFNs in operation.*

We have taken into consideration the BMR[58] specification for required capacity which can currently only be met by installing REFCLs. Powercor has made a case that a spare REFCL should be carried to mitigate risk of not meeting required capacity due to a failure in a REFCL installation. There is little experience with the REFCL technology and Powercor is unable to determine failure rates with confidence. We consider it prudent to retain a spare REFCL if needed.

We consider 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).

Testing Trailer

Powercor intends to purchase a second testing trailer[59]. It argues that:

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55 Powercor: *REFCL2_MOD.01 Expenditure build-up model (tranche two),* April 2018.

56 AusNet Services: *ASN Total Cost Model tranche two*, April 2018.

57 Powercor: *REFCL contingent project application*, April 2018.

58 *Electricity Safety (Bushfire Mitigation) Amendment Regulations*, 2016.

59 Powercor: *REFCL contingent project application (tranche two*), April 2018.

- the existing trailer will be occupied by tranche one activities during the tranche two installation timeframe
- two trailers will be required to enable testing and commissioning of different zone substations at one time
- two trailers will be required for annual testing.

We consider 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).

Earth Grids and CT replacements

The Powercor application[60] includes a new allocation for earth grids and CT replacements to account for the situation where the performance of a second or subsequent GFN is impaired when the first is handling a fault. Powercor also determined that existing current transformers are insufficient to meet the required sensitivity specified by the regulations.

Powercor proposed to upgrade earth grids and CTs at multi GFN sites at a cost of $2.6 million.[61] Experience to date with REFCLs has indicated these devices are susceptible to stray earth currents. This can only be overcome by minimising stray earth currents which requires a substantial increase in earth segregation for each device. We consider this a reasonable approach in order to meet the regulated specifications.

We consider 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).

Testing and commissioning

The RIS did not include REFCL testing and commissioning, though it is a significant cost item in the Powercor application. Also, the Powercor application allocated $3.9 million[62] to this in tranche two compared to $3.1 million[63] in tranche one. This allowance would provide for portable diesel generators to supply HV customer sites. We acknowledge that the size, complexity of the networks and number of GFNs has increased and consider that the effort involved in testing and commissioning justifies the increased allocation.

We consider 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).

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60 Powercor: *REFCL contingent project application*, April 2018.

61 Powercor: *REFCL2_MOD.01 – Expenditure build-up model (tranche two)*, April 2018.

62 Powercor: *REFCL2_MOD.01 – Expenditure build-up model (tranche two)*, April 2018.

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

Feeder works

Network balancing

Powercor has identified costs of $16.8[64] million in tranche two against $11.7[65] million in tranche one for network balancing works to integrate the REFCLs including:

- admittance balancing units (single and three phase)
- re-cabling
- re-phasing.

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.

We benchmarked Powercor against the RIS and AusNet Services in tranche one. We note that the network size and complexity in tranche two is at least 50%[66] [67] greater than in tranche one and therefore consider these costs are justified. AusNet Services is proposing $16.3[68] million for this activity in tranche two, which also represents the increased size and complexity of the tranche two networks. 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[69] for the increased costs in comparison to the RIS, advising:

- REFCL trials performed since the RIS was conducted provide a basis for more accurate estimates
- the RIS was tabled in 2015 before a detailed design was produced, and site considerations 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 BMR is far higher than is possible under that strategy.[70]
- Powercor has identified a combination of approaches[71] for tranche two are necessary including:

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64 Powercor: *REFCL2_MOD.01 Expenditure build-up model (tranche two),* April 2018.

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

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

67 Powercor: *REFCL2_MOD.01 Powercor, Expenditure build-up model (tranche two),* April 2018. There are 51 feeders in tranche two compared with 34 in tranche one.

68 AusNet Services: *ASN Total Cost Model, CONFIDENTIAL*, April 2018.

69 Powercor: *Surge Arrester replacement re REFCL installation - review of Powercor surge arrester replacement strategy GHD,* March 2017.

70 Powercor: *Contingent Project Application REFCL program (tranche one),* March 2017, pp. 41-44.

71 Powercor: *Contingent Project Application REFCL program (tranche two),* April 2018, p. 28.

- installation of single-phase admittance balancing units for every 300m of single-phase underground cable
- overhead re-phasing works for every 15km of single-phase overhead line
- installation of three-phase admittance balancing units between remote-controlled switching sections, as well as between strategically located manually-operated isolatable sections
- installation of an additional three-phase admittance balancing unit for each feeder to cater for the dynamic nature of network operations
- installation of fuse savers for any fused sections with overhead line length greater than 9km or 225m of underground
- cable or the equivalent combination of both overhead line and underground cable
- where a fuse-saver is unable to be deployed due to high fault levels, installation of an ACR to clear each fault
- installation of a three-phase section to prevent the feeder continually tripping during days of high sensitivity
- upgrade of HV regulators to closed delta configurations with parallel control.

AER technical staff conducted site inspections at trial sites operated by AusNet Services and Powercor during tranche one. 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 only cost that has increased as a result of the new learnings is the cost of ACRs. Powercor advises that:

> *the revised approach*[72] *utilises a greater proportion of three phase balancing units. The three-phase unit allows tuning of the level of supplementary capacity provided for each section of the feeder, and can be remote controlled. The dynamic feature of three phase balancing unit enables faster restoration following a fault. The additional units enable us to rebalance the feeder following faults where the feeder is partially restored using manual switches.*

We note that single-phase balancing units and re-phasing of the line deliver fixed levels of capacitance. The switching sections are therefore balanced for the static configuration of the network and do not allow for rebalancing of the feeder following a fault using both manual switches and remote control devices. The additional three phase balancing units therefore ensure that required capacity can be maintained on total fire ban days and the maximum number of customers kept on supply during faults. We therefore accept Powercor's reasoning.

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[72] Powercor *Contingent Project Application REFCL program: (tranche two),* April 2018, p. 29.

The tranche one application outlined a detailed risk and governance strategy[73] and this approach has been carried over to tranche two. We reviewed this strategy and note the AusNet Services approach is similar to the Powercor approach.[74] We also consider the Powercor approach is in accordance with industry norms for complex capital works and is reasonable.

We consider 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).

Line hardening

Line hardening works include the major activity of replacing surge arrestors and other items of compatible equipment.

Surge arrestors

Powercor proposes $10.8 million[75] in tranche two compared with $7.7 million[76] in tranche one, and for line hardening works to integrate the REFCLs. We note that the additional cost is directly due to the surveyed asset population requirement which is higher in tranche two. The unit cost has actually decreased.

The line hardening works include surge arrestor replacement. Powercor presented its Surge Arrestor Strategy and GHD review[77]. The strategy includes:

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

Powercor proposed replacing a proportion of surge arrestors[78] for tranche two of the REFCL program. Powercor's per unit costings are the same as those for tranche one. We note their costs were similar to AusNet Services' in tranche one.[79] The RIS presented an estimated cost of $1 000 per surge arrestor, Powercor's per unit cost compares favourably with this.

The Bushfire Mitigation Regulation Amendment Regulatory Impact Statement (RIS)[80] considered the replacement of one in three surge arrestors reflected 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

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73 Powercor: *Contingent Project Application REFCL program: (tranche one),* March 2017, p. 51.

74 AusNet Services: *REFCL Program Network Balancing Strategy 2017,* p. 11 and 13.

75 Powercor: *REFCL2_MOD.01 Expenditure build-up model (tranche two),* April 2018.

76 Powercor: *REFCL1_MOD.01 Expenditure build-up model (tranche one),* March 2017.

77 Powercor: *Surge Arrester replacement re REFCL installation Review of Powercor surge arrester replacement strategy GHD,* March 2017.

78 Powercor: *Contingent Project Application REFCL program: (tranche two),* April 2018 p. 44-45.

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

80 DELWP: *Bushfire Mitigation Regulations Amendment Regulatory Impact Statement,* 2015, p. 69.

work[81] by the an independent testing laboratory, commissioned by Powercor, identified specific makes and models of existing installed surge diverters requiring 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. Given this process, we consider the estimated replacement volumes are to acceptable.

These costs reflect surge arrestor costs previously accepted by us in the determination for Powercor, the tranche one contingent project application and in an earlier pass through application. The Powercor costs are also below the RIS estimate. On this basis, the AER accepts the costs as proposed by Powercor in the contingent project application.

We consider 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).

Compatible Equipment

Powercor has applied the same per unit costs for tranche two for compatible equipment works to integrate the REFCLs as for tranche one[82] including:

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

Powercor has estimated the costs of ACR replacements[83] are $24 347, and upgrades are $5 976. These are lower than AusNet Services[84] estimates. The RIS[85] estimated upgrade costs of $70 000 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 does not reflect a genuine cost difference.

We consider 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).

Powercor estimated the cost of HV regulator replacements[86] are $145 694, which is the same as the tranche one estimate. Powercor estimates the cost of upgrades is $13 623. These estimates are lower than those in the AusNet Services application, and within the range of the RIS estimates for upgrade costs of $0-$375 000 each.

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

82 Powercor: *REFCL2_MOD.01 Expenditure build-up model (tranche two),* April 2018.

83 Powercor: *REFCL2_MOD.01, Expenditure build-up model (tranche two),* April 2018.

84 AusNet Services: *REFCL Contingent project application Total Cost Model*, April 2018.

85 DELWP: Bushfire Mitigation Regulations Amendment Regulatory Information Impact Statement, 2015.

86 Powercor: *REFCL2_MOD.01 Expenditure build-up model (tranche two),* April 2018.

We have considered the expenditure proposed by Powercor in relation to HV regulators and accept that volumes and approach are aligned with the balancing strategy and actual asset base. We accept that the tranche two networks are significantly larger and more complex than those in tranche one, and that all of the increased costs relate to this. We consider that the volume and unit rates proposed by Powercor are reasonable.

We consider 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).

Victorian Electricity Distribution Code - HV customers

In its initial application, Powercor allocated $19.2[87] million for VEDC works to integrate REFCLs.

Section 1.5 describes:

- the treatment of HV customers in tranche one
- the changes to the VEDC as a result of a process conducted by the ESCV
- the treatment of HV customers in tranche two.

As outlined in section 1.5, under the revised VEDC effective from 20 August 2018, there is a transfer of risk and obligation to HV customers, which means that they need to adopt a strategy at their own cost to make their systems compatible with a network with installed REFCLs.

Powercor submitted a revised version of the application[88] anticipating an amendment to the VEDC which was subsequently finalised. The revised application argues that even though the risk and obligation has transferred to the HV customers, there are residual costs, which must be borne by Powercor to accommodate these customer works.

Powercor estimates these residual costs are $1.984[89] million. These costs average $76 000 per connection.

The residual relates to:

- installation of ACRs at all HV customer sites
- installation of neutral displacement protection coordination equipment for generator HV customers
- costs for Powercor to independently verify third party reports that HV customers are appropriately hardened or able to be isolated from our network during the operation of a REFCL.

These costs relate to 24 isolation substations anticipated to be installed at 23 sites, and 2 for customers who have elected to harden their installations.

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87 Powercor: *REFCL2_MOD.01 Expenditure build-up model (tranche two),* April 2018.

88 Powercor: *Contingent project application*, email, 15 June 2018, (anticipating Voltage standard amendment).

89 Powercor: *REFCL2_MOD.01 Expenditure build-up model (tranche two)*, 15 June 2018, (anticipating Voltage standard amendment).

We consider there is a need for ACRs to isolate customers where a customer's site is directly connected to the network, as would be the case where a customer chooses to harden its site. This is intended to mitigate a significant risk of a cross-country fault which Powercor would wish to detect and isolate.

In regard to the treatment of existing HV customers who have indicated that they wish to have an isolation transformer installed, we agree with Powercor that these customers may change their strategy due to the amendment to the VEDC. Further, since the customers will now manage the implementation of their selected strategy, Powercor does not know whether the isolation transformer will be connected close to the point of connection.

Powercor argues that it does not have a legal basis to charge customers with an existing connection for an ACR as a connection alteration under the customer connection policy[90] unless a customer applies for a connection alteration. Powercor states that new customers who apply for an HV connection would be liable under the connection policy for an ACR where Powercor determines it is necessary, as new customers must design their installation to operate with REFCLs in compliance with the recently amended VEDC.

We consider the requirement for ACRs to be a transitional issue relating only to existing customers. The need for ACRs is driven by uncertainty that all affected customer installations will be upgraded in time for commissioning of the REFCL in accordance with the mandated timetable. If this expenditure were not allowed, the implementation timetable of REFCL operation may be jeopardised by parties outside Powercor's control. For this reason we consider it an acceptable inclusion in the contingent project application.

We also agree that:

- neutral displacement protection is an acceptable inclusion in the tranche two project application for the reasons set out in Powercor's revised application
- backup generation to isolate customers during commissioning is an acceptable inclusion in the tranche two project application for the reasons set out in Powercor's revised application
- costs to independently verify third party reports that HV customers are appropriately hardened or able to be disconnected from the Powercor network is an acceptable inclusion in the tranche two project application for the reasons set out in Powercor's revised application.

Powercor also included a claim for $1.0 million for Distribution Code Voltage Variation allowance for treatment of customers as an operational expenditure allocation which we did not allow for due to the revised VEDC.

Overall, we have reduced the allowed capital expenditure on the compliance with the Victorian Electricity Distribution Code and HV customers by $17.2 million. This amounts to 13.5% of the total application.

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90 Powercor: *Connection policy,* July 2016.

We consider 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).

3.5.2 Other capital expenditure

Powercor sought $5.4 million[91] for contracts to integrate the REFCLs including:

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

We have reviewed these costs and they compare reasonably with the costs we approved for tranche one. The escalation is in proportion to the increase in size and complexity of the zone substations and networks in tranche two.

We consider 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).

[91] Powercor: *REFCL2_MOD.01 Expenditure build-up model (tranche two),* April 2018.

3.6 Operating expenditure (Opex)

3.6.1 Forecast

Powercor presented an overall operational expenditure requirement of $5.8 million[92] in its application. The following tables present a breakdown of costs.

Table 3.7: Opex cost breakdown

Opex	Total cost ($'000) tranche one[93]	Total cost ($'000) tranche two
Incremental technical support p.a.	87.0	87.0
Incremental re-balancing works p.a.	166.7	166.7
Incremental re-balancing works (p.a. per feeder cost)	2.9	2.9
Incremental compliance testing (p.a. per feeder cost)	8.9	8.9

Table 3.8: Feeder count tranche one

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

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

92 Powercor: *REFCL Contingent project application (tranche two),* April 2018, p. 58, table 7.11.

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

94 Powercor: *REFCL2_MOD.01 Expenditure build-up model (tranche two),* April 2018.

Table 3.9: Feeder count tranche two

Zone substation	Number of feeders
Ballarat North	12
Ballarat South	9
Bendigo Terminal Station	8
Bendigo	7
Charlton	6
Geelong	9
Total	**51**

Source: Powercor: *Contingent project application, REFCL program (tranche two),* April 2018 Expenditure build-up model.

Table 3.7 indicates the costs for incremental technical support, balancing and compliance have not changed from tranche one and are in proportion to network size. Also, Powercor includes Project Management Office costs of $4.3 million[95] which is similar to the amount we approved for tranche one.

Powercor also included a claim for $1.0 million[96] for Distribution Code Voltage Variation allowance for treatment of customers as an operational expenditure allocation which we removed due to the revised VEDC (see section 3.5.1).

We consider 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).

3.6.2 Comparison of Powercor and AusNet Services

We benchmarked similar operational works. Powercor estimated operational expenses of $4.8 million[97] for a collection of expenses. For a similar set of expenses AusNet Services has capitalised an amount of $5.4 million[98] and allocated operational expenses of $2.2 million.

These include:

- live-line equipment purchases
- survey costs
- annual compliance test sites

95 Powercor: *REFCL2_MOD.01 – Expenditure build up model (tranche two),* April 2018.

96 Powercor: *REFCL2_MOD.01 – Expenditure build up model (tranche two),* April 2018.

97 Powercor: *REFCL2_MOD.01 – Expenditure build up model (tranche two),* April 2018.

98 AusNet Services: *ASN Total cost model, CONFIDENTIAL,* April 2018.

- cables – reactive testing, repairs and replacements
- technical support
- re-balancing
- alternative technologies
- phase ID tools and training

Table 3.8 Opex benchmarks

Comparison	AusNet Services ($'000)	Powercor ($'000)
Opex	2 233	4 837
Capex	5 369	-
5 year total	7 602	4 837
Average per Zone substation (tranche two)	950	967
Average per Zone substation (tranche one)	838	829

Table 3.8 compares AusNet Services and Powercor. We note that average cost per substation has increased in comparison to tranche one. We accept that there is a proportional increase in the size and complexity of the networks in tranche two.

We consider 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).

4 AER's calculation of the annual revenue requirement

4.1 Capital expenditure

Powercor proposed $127.7 million capital expenditure to provide for REFCL installation and supporting works for six zone substations in tranche two of the REFCL program.[99] Powercor provided supporting evidence and detailed cost estimates to make the contingent project application.[100] These costs have not been included in the 2016-20 distribution determination given that the assets were not part of the planned replacement program for that period.

We have reduced the allocation for HV customer isolation transformers by $17.2 million, as set out in 3.5.1.

We have approved a capital expenditure of $110.5 million.

As set out in the following section, to adjust the capex amounts sought by Powercor we calculated the adjustment to the inputs into the PTRM in real 2015 dollars.

4.2 Operating expenditure

Powercor claimed $6.4[101] million for operating expenditure to provide for REFCL installation and supporting works for six zone substations in tranche two of the REFCL program. Powercor provided supporting evidence and detailed cost estimates to make the contingent project application.[102] These costs were not included in the 2016-20 distribution determination given the assets were not part of the planned replacement program for that period.

We have reduced the allocation for HV customer’s by $1.0 million, as set out in 3.5.1.

We have approved an incremental operating expenditure of $4.8 million.

As set out in the following section, to adjust the opex amounts sought by Powercor we calculated the adjustment to the inputs in the PTRM 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. We have made an allowance for this. The time cost of money is based on the most recent rate of return for Powercor, as set out in our 2016–20 distribution determination.[103]

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99 Powercor: *REFCL2_MOD.01 Expenditure build-up model (tranche two),* April 2018.

100 Powercor: *REFCL Contingent project application (tranche two),* April 2018.

101 Powercor: *REFCL Contingent project application (tranche two),* April 2018, p. 58, Table 7.11.

102 Powercor: *REFCL2_MOD.01 Expenditure build-up model Contingent project application (tranche two),* April 2018.

103 AER: *Final decision, Powercor distribution determination 2016 to 2020.*

We have also updated the values for X-factor and return on debt in year 2 to 4 under the trailing average methodology which now applies.[104]

The smoothed revenue arising from this contingent project is then calculated by adjusting the X-factors for years 4 and 5 to maintain final year revenue within 3.0% of the target value.

4.4 Calculation of revenue requirement

Table 4.1: AER Allowance: Powercor contingent project revenue requirement, 2016-2020 ($m, nominal)

	2016	2017	2018	2019	2020
Return on capital	0.0	0.1	0.1	4.3	7.0
Return on capital (regulatory depreciation)	0.0	0.0	0.0	5.4	7.0
Operating expenditure	0.0	0.0	2.7	2.1	0.6
Revenue adjustments	0.0	0.0	0.0	0.0	0.0
Net tax allowance	0.0	-0.0	-0.0	0.7	0.7
Annual revenue requirement (unsmoothed)	0.0	0.0	2.7	12.5	15.4
Expected revenue (smoothed)	**0.0**	**0.0**	**0.0**	**13.9**	**16.9**
% change to revenue	**0.00%**	**0.00%**	**0.00%**	**2.15%**	**2.47%**
X-factors	**7.80%**	**4.68%**	**-0.81%**	**-3.39%**	**-3.39%**

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

4.5 Inflation revocation PTRM

The contingent project application was made using a version of the AER's post-tax revenue model (PTRM) which included an expected inflation input arising from the 2016-20 distribution determination. Subsequent to this application, on 25 May 2018, we substituted the 2016-20 distribution determination to correct for an inflation estimation error and published an amended version of the PTRM. Our decision for this contingent project therefore uses the amended version of the PTRM.[105]

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104 In this decision, the year 4 return on debt update has been further updated following RBA data revisions.

105 AER: *Letter proposing revocation and substitution of AusNet Services distribution determination 2016-2020.*

5 AER determination

5.1 AER determination

On 31 August 2018, the AER Board determined that the Powercor application for contingent project funding lodged 20 April 2018 was approved but with modifications to the amounts sought. Powercor submitted its application in real $2015. We presented calculations for incremental capital and operating expenditure in each remaining year of the regulatory control period in real $2015. This is because the PTRM 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 to be as follows.[106]

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

	2016	2017	2018	2019	2020
Incremental capital expenditure	0.0	0.0	64.5	46.0	0.0
Incremental operating expenditure	0.0	0.0	2.53	1.85	0.45

Table 5.1 demonstrates:

- the total capital expenditure we consider is reasonably required for the purpose of undertaking the contingent project is $110.5 million[107]
- the contingent project has commenced and the likely completion date is 30 April 2021.[108]

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),[109] 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 as follows.[110]

106 NER, clause 6.6A.2(e)(1)(i).

107 NER, clause 6.6A.2(e)(1)(ii).

108 NER, clause 6.6A.2(e)(1)(iii).

109 NER, clause 6.6A.2(e)(2).

110 NER, clause 6.6A.2(e)(1)(iv).

Table 5.2 – Incremental revenue calculation and X-factors ($m, nominal)

	2016	2017	2018	2019	2020
Return on capital	0.0	0.1	0.1	4.3	7.0
Return on capital (regulatory depreciation)	0.0	0.0	0.0	5.4	7.0
Operating expenditure	0.0	0.0	2.7	2.1	0.6
Revenue adjustments	0.0	0.0	0.0	0.0	0.0
Net tax allowance	0.0	-0.0	-0.0	0.7	0.7
Incremental annual revenue requirement (unsmoothed)	0.0	0.0	2.7	12.5	15.4
Expected revenue (smoothed)	**0.0**	**0.0**	**0.0**	**13.9**	**16.9**
% change to revenue	**0.00%**	**0.00%**	**0.00%**	**2.15%**	**2.47%**

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:

- the annual revenue requirement for each regulatory year in the remainder of the regulatory control period
- the X-factor for each regulatory year in the remainder of the regulatory control period.[111]

We determine the effect to be as follows.

Table 5.3 – Annual revenue requirement and X-factors ($m, nominal)

	2016	2017	2018	2019	2020
Annual revenue requirement (unsmoothed)	586.29	589.27	637.46	694.12	718.30
Expected revenue (smoothed)	621.77	606.45	625.56	661.96	700.48
X-factors	7.80%	4.68%	0.81%	-3.39%	-3.39%

We have determined incremental contingent project unsmoothed revenue amount to be $30.6 million ($nominal). This is the amount that Powercor will recover from customers over

111 NER, clause 6.6A.2(h)(3).

three years commencing 1 January 2018. This is different from the building block amount of $37.1 million ($nominal) proposed by Powercor.

We further determine the smoothed annual revenue requirement should be adjusted to $3.216 total billion ($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 $3.225 billion ($nominal).

We have not amended the roll-forward model.

This corresponds to an increase in average distribution network prices of 2.15% in 2019 and 2.47% in 2020.

Appendix A – Impact on a typical Customer Bill

Our estimate of the potential impact this decision will have for Powercor's residential customers is based on the typical annual electricity usage of around 4,000kWh per annum for a residential customer in Victoria.[112] Therefore, customers with different usage will experience different changes in their bills. We also note that there are other factors, such as transmission network costs, metering, wholesale and retail costs which affect electricity bills. The potential impact on small business customers, however, is estimated differently. We make a pro-rata adjustment to the annual bill for a typical small business customer as calculated in our 2016–20 distribution determination, reflecting the updates made to residential customer bills in this decision. This is due to a limitation in the Victorian Energy Compare comparison tool.[113]

Table A shows the estimated annual average impact of our determination on Powercor's REFCL contingent project, tranche two on the average residential and small business customers' annual electricity bills. As explained above, these bill impact estimates are indicative only, and individual customers' actual bills will depend on their usage patterns and the structure of their tariffs.

Table A – Estimated impact of AER's decision on Powercor's REFCL contingent project, tranche two on annual electricity bills for 2019 and 2020 ($, nominal).

Impact on Customer Bill	2018	2019	2020
Change to distribution component for contingent project (%)		**2.2%**	**2.5%**
Residential Customers			
Distribution component ($)[a]	458	467	479
Residential annual electricity bill ($)[b]	1,830[b]	1,840	1,851
Annual change (%)		0.5%	0.6%
Annual change ($)		10	12
Small Business Customers			
Distribution component ($)[a]	1,007	1,029	1,054
Small business annual electricity bill ($)[c]	4,029[c]	4,050	4,076
Annual change (%)		0.5%	0.6%
Annual change ($)		22	25

a Distribution network proportions are consistent with the AER's 2016-20 distribution determination.

b Based on average standing offers at June 2017 on Victorian Energy Compare comparison tool (postcode 3134) using annual bill for typical consumption of 4000kWh per year.

c Based on typical small business annual bill as per the AER's 2016-20 distribution determination, using a pro-rata step change reflecting a similar proportion to the residential bill updates.

Source: AER analysis

112 ESC, *Victorian energy market report 2016-17,* November 2017, p. 28.

113 Victorian Energy Compare (AGL standing offer)

Appendix B - List of stakeholder submissions

Submission from	Date
Victorian Minister for Energy, Environment and Climate Change	15 June 2018
Groundline Engineering	15 June 2018
Powercor	15 June 2018