Powercor

Contingent project application

REFCL program: tranche one

March 2017

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Contents

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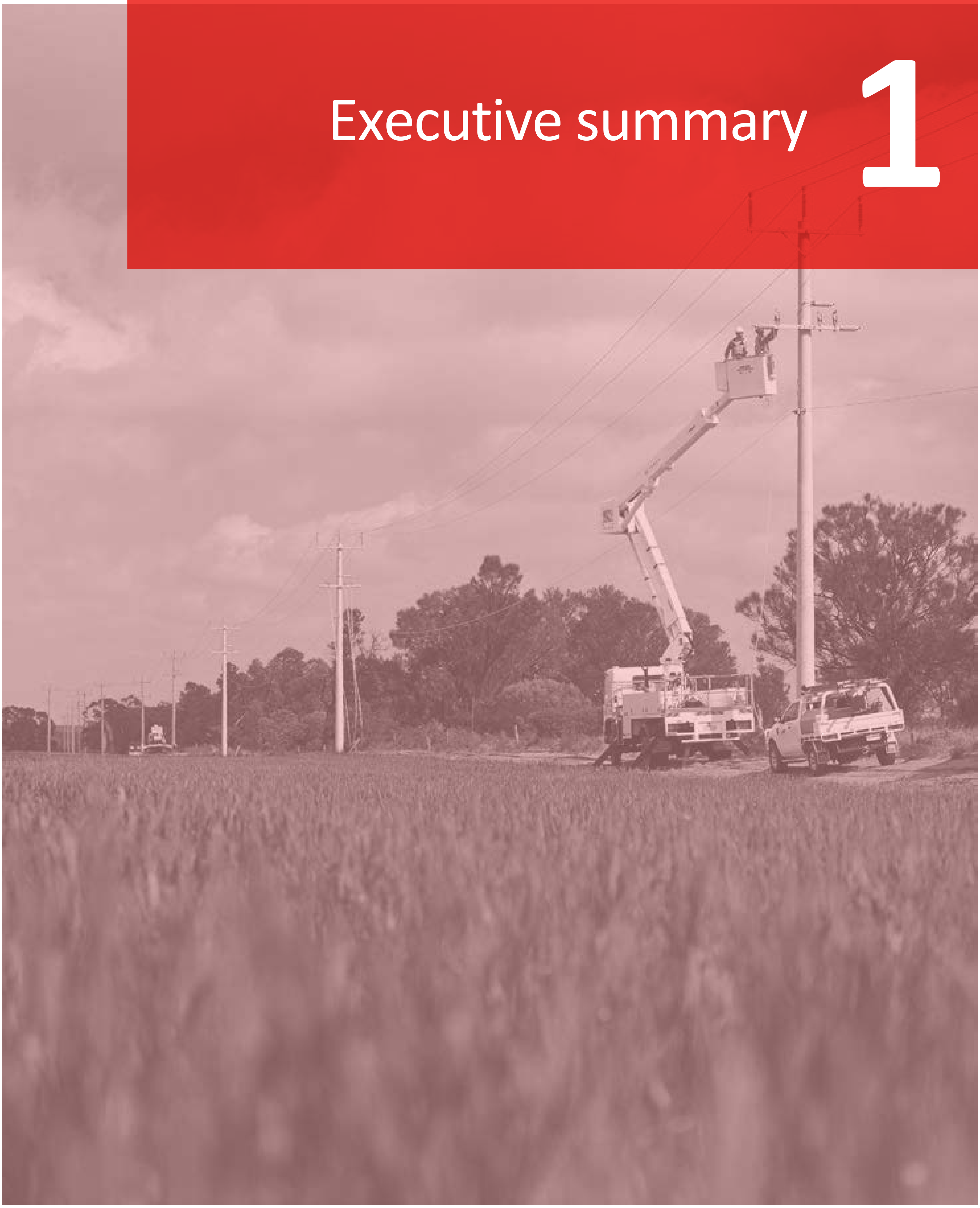
1 Executive summary



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On 1 May 2016, the Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016 (**Amended Bushfire Mitigation Regulations**) were implemented in Victoria. To comply with the Amended Bushfire Mitigation Regulations, we are required to install Rapid Earth Fault Current Limiters (**REFCLs**).

A REFCL is a network protection device, normally installed in a zone substation, that can reduce the risk of a fallen powerline causing a fire-start. It is capable of detecting when a powerline has fallen to the ground and (almost instantaneously) reduces the voltage on the fallen line.

The installation and commissioning of REFCLs, however, represents a fundamental change to the operation of our network. For example, it requires significant investment in primary and secondary plant to reconfigure our zone substations. It also necessitates additional network hardening works to ensure our assets can withstand the over-voltages that will occur when a REFCL operates.

The expenditure required to install REFCLs on our network was not included in our revenue allowance for the 2016–2020 regulatory control period. Instead, the Australian Energy Regulator's (**AER**) final decision specified the installation of REFCLs as a contingent project (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).

Our contingent project application sets out the expenditure required to install REFCLs at six locations on our network. Our expenditure forecast is based on the functional design scopes for these locations, and accordingly, our expenditure reflects the variability in the characteristics of each REFCL site.

A summary of the revenue impact of our proposed expenditure is set out in table 1.1.

Table 1.1 Summary of incremental revenue requirements ($m, nominal)

Building block components	2016	2017	2018	2019	2020
Return on capital	-	0.1	3.2	5.6	5.4
Return of capital (regulatory depreciation)	-	0.0	2.3	3.1	3.3
Operating expenditure	-	2.2	2.3	0.4	0.8
Net tax allowance	-	-0.0	0.3	0.3	0.4
Annual revenue requirement (unsmoothed)	-	2.2	8.2	9.5	9.9
Annual revenue requirement (smoothed)	**-**	**0.0**	**9.6**	**10.0**	**10.5**

Source: Powercor

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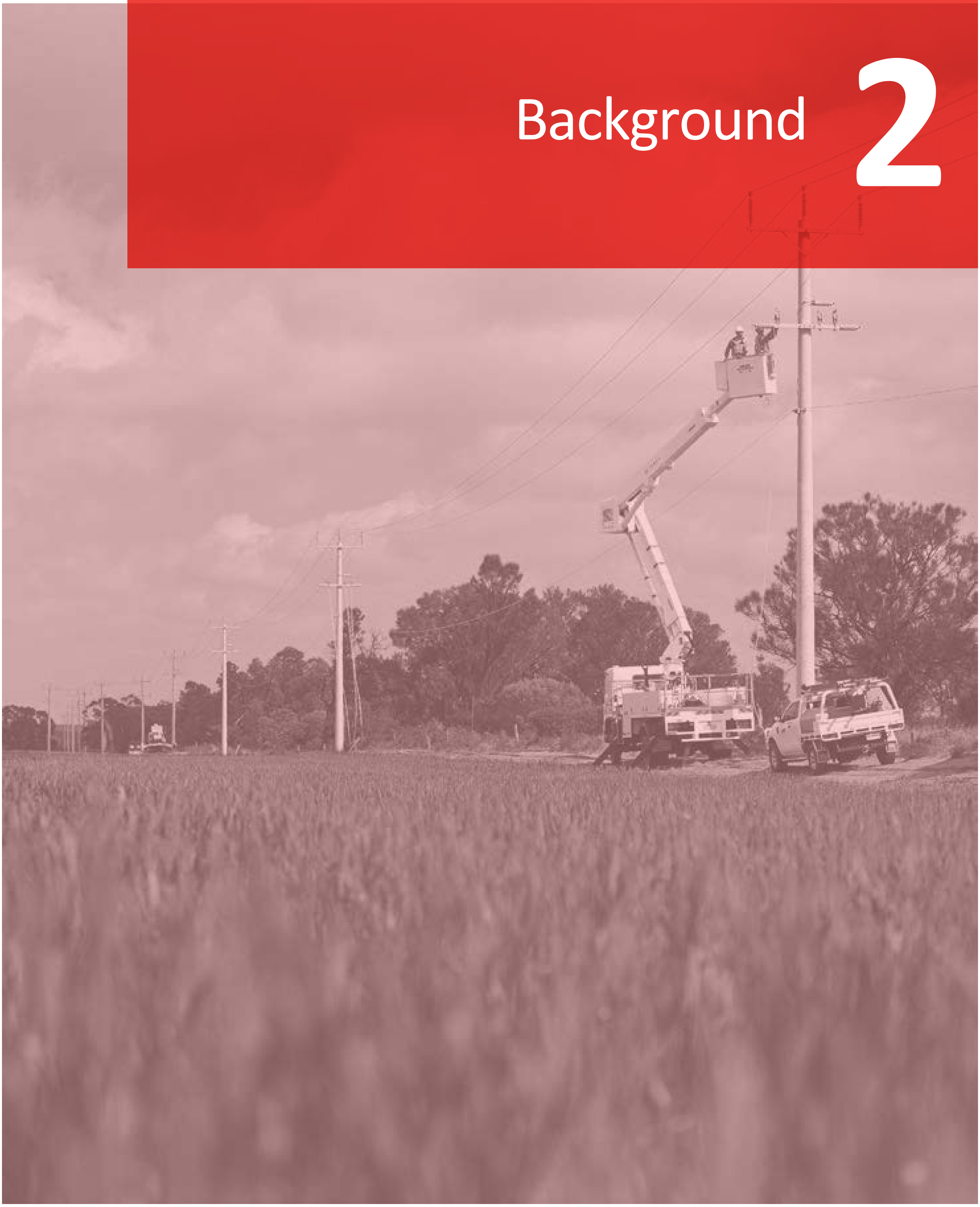

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A contingent project is a project assessed by the AER as being reasonably required, but for which uncertainty exists regarding the timing or costs. The associated expenditure, therefore, is excluded from ex-ante capital expenditure allowances until a defined trigger event occurs.

At the time of making its final decision for Powercor for the 2016–2020 regulatory control period, expected amendments to the *Electricity Safety (Bushfire Mitigation) Regulations 2013* had not been finalised. To ensure consumers did not pay for an uncertain event, the AER's final decision accepted the installation of REFCLs as a contingent project.

This section sets out background regarding the requirement to install REFCLs, including the following:

- the Powerline Bushfire Safety Taskforce (**PBST**);
- the Regulatory Impact Statement (**RIS**);
- the Amended Bushfire Mitigation Regulations; and
- the Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme).

Further background on the relevant regulatory requirements under the National Electricity Rules (**the Rules**) is set out in section 4.

2.1 Powerline Bushfire Safety Taskforce

Following the Black Saturday bushfires in 2009, the Victorian Government established the Victorian Bushfire Royal Commission (**VBRC**) to consider how bushfires can be better prevented and managed in the future. In July 2010, the VBRC's final report was provided to the Victorian Government.

The VBRC's final report made a number of recommendations, including the following:[1]

> *[t]he State amend the Regulations under Victoria's Electricity Safety Act 1998 and otherwise take such steps as may be required to give effect to the following:*
>
> – *the progressive replacement of all SWER (single-wire earth return) power lines in Victoria with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk…*
>
> – *the progressive replacement of all 22-kilovolt distribution feeders with aerial bundled cable, underground cabling or other technology that delivers greatly reduced bushfire risk as the feeders reach the end of their engineering lives.*

As part of the Victorian Government's consideration of the recommendations made by the VBRC in its final report, the PBST was established. The PBST was required to investigate new cost efficient and effective technologies and operational practices to reduce catastrophic bushfire risk.

The PBST identified REFCLs installed in zone substations as an efficient and effective technology. A REFCL is a network protection device, normally installed in a zone substation, that can reduce the risk of a fallen powerline causing a fire-start. It is capable of detecting when a powerline has fallen to the ground and (almost instantaneously) reduces the voltage on the fallen line.

The PBST estimated the relative reduction in the likelihood of multi-phase powerlines starting bushfires to be approximately 70 per cent with the installation of REFCLs.[2]

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[1] 2009 Victorian Bushfires Royal Commission, *Final Report, Summary*, July 2010, recommendation 27.

2.2 Regulatory impact statement

On 17 November 2015, the Department of Economic Development, Jobs, Transport and Resources (**DEDJTR**) published a RIS for proposed amendments to the *Electricity Safety (Bushfire Mitigation) Regulations 2013*.[3] The RIS assessed the costs of reducing the likelihood that electricity distribution powerlines start bushfires, including:

- enhanced network protections for polyphase powerlines (i.e. install REFCLs);
- enhanced network protections for single wire earth return powerlines; and
- requiring powerlines in declared areas to be put underground or insulated.

For the reasons set out in this contingent project application, we consider the cost estimates set out in the RIS understate the true cost of installing REFCLs.

2.3 Amended Bushfire Mitigation Regulations

On 1 May 2016, the Victorian Government passed legislation—the *Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016* (**Amended Bushfire Mitigation Regulations**)—to implement the PBST's findings.[4] The Amended Bushfire Mitigation Regulations now require our bushfire mitigation plan (**BMP**) to include details of the preventative strategies and programs by which we will ensure each polyphase electric line originating from selected zone substations in our network meet specified capacity requirements.

The Amended Bushfire Mitigation Regulations further specify the timeframes by which the selected zone substations must meet these capacity requirements. That is, schedule two of the Amended Bushfire Mitigation Regulations assigns a number of 'points' to each of the selected zone substations. We are then required to ensure the following:[5]

- at 1 May 2019, the points set out in schedule two [of the Amended Bushfire Mitigation Regulations] in relation to each zone substation upgraded, when totalled, are not less than 30;
- at 1 May 2021, the points set out in schedule two in relation to each zone substation upgraded, when totalled, are not less than 55; and
- on and from 1 May 2023, in our supply network, each polyphase electric line originating from every zone substation specified in schedule two has the required capacity.

2.4 Bushfire Mitigation Civil Penalties Scheme

On 7 February 2017, the Victorian Government introduced a bill into Parliament to amend the *Electricity Safety Act 1998*. The proposed amendment—the Bushfire Mitigation Civil Penalties Scheme—includes financial penalties of up to $2 million per point for any difference between the total number of required substation points prescribed in the Amended Bushfire Mitigation Regulations and that actually achieved (as set out in section 2.3). The scheme also includes a daily penalty up to $5,500 per point for each day that a contravention with the Amended Bushfire Mitigation Regulations continues.

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2 Powerline Bushfire Safety Taskforce, *Final report*, 30 September 2011, p. 5.

3 ACIL Allen Consulting, *Regulatory Impact Statement, Bushfire Mitigation Regulations Amendment*, 17 November 2015.

4 Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016.

5 Electricity Safety (Bushfire Mitigation) Regulations 2013, Authorised version no. 004, cl. 7(3)(a).

Our REFCL program 3

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This section provides an overview of our REFCL program, including our REFCL tranches and trials undertaken by us and other distributors.

3.1 Our REFCL tranches

Our REFCL program has been structured into three separate tranches in order to achieve the 'points' requirement set out in the Amended Bushfire Mitigation Regulations (see section 2.3, above). These tranches are shown in figure 3.1.

Figure 3.1 REFCL tranches

Tranche one	Tranche two	Tranche three
• Camperdown (CDN) • Colac (CLC) • Castlemaine (CMN) • Maryborough (MRO) • Winchelsea (WIN) • Eaglehawk (EHK)	• Bendigo TS (BETS) • Charlton (CTN) • Bendigo (BGO) • Ballarat South (BAS) • Ballarat North (BAN) • Geelong (GL)	• Corio (CRO) • Koroit (KRT) • Stawell (STL) • Waurn Ponds (WPD) • Hamilton (HTN) • Ararat (ART) • Merbein (MBN) • Terang (TRG)

Source: Powercor, *Bushfire Mitigation Plan, Revision 3.1*, 5 December 2016

This contingent project application only includes expenditure associated with the zone substations set out in tranche one. Our timeframes for our tranche one sites are shown in table 3.1.

Table 3.1 REFCL installation timeframes: tranche one

REFCL site	Planned installation	Required capacity
Camperdown (**CDN**)	April 2018	April 2019
Colac (**CLC**)	March 2019	April 2019
Castlemaine (**CMN**)	May 2018	April 2019
Maryborough (**MRO**)	April 2019	April 2019
Winchelsea (**WIN**)	April 2019	April 2019
Eaglehawk (**EHK**)	June 2019	April 2021

Source: Powercor, *Bushfire Mitigation Plan, Revision 3.1*, 5 December 2016

The zone substations set out in tranche two will be included in a separate (future) contingent project application. The zone substations set out in tranche three are expected to be included in our regulatory proposal for the 2021–2025 regulatory control period.

For clarity, expenditure associated with meeting our obligations under the Amended Bushfire Mitigation Regulations for declared areas will be included in our tranche two application, and our regulatory proposal for the 2021–2025 regulatory control period.

3.2 Our REFCL trials

The use of REFCLs in Australia is currently novel. Further, the use of REFCLs in other countries has focused on reducing safety risks and improving reliability, and not bushfire mitigation.

Accordingly, we and other Victorian distributors have been undertaking trials to better understand the impact of installing and operating REFCLs on our networks for the purpose of reducing bushfires.

3.2.1 Gisborne and Woodend

The AER's final determination for the 2016–2020 regulatory control period included funding to install REFCLs on our network—at our Gisborne (**GSB**) and Woodend (**WND**) zone substations. This funding is separate to the REFCL tranches set out in figure 3.1.

The commissioning of our two REFCL units at WND and one at GSB is ongoing, and at the time of lodging this contingent project application we have not yet met all the performance requirements set out in the Amended Bushfire Mitigation Regulations (i.e. we have not yet met the 'required capacity').[6] Notwithstanding this, our GSB and WND experience is helping demonstrate how operating a REFCL may impact our overall network (with a particular focus on surrounding system resilience, capacitive balancing, and operational matters). The learnings from these trials are being carried forward to our remaining REFCL projects—for example, the commissioning of REFCLs at GSB and WND highlighted the following:

- achieving performance requirements may necessitate multiple REFCL units at particular zone substations;
- only selected surge arrestors types require replacement;
- only selected Automatic Circuit Reclosers (**ACRs**) require replacement;
- only selected switchgear requires replacement;
- a multi-faceted approach to capacitive balancing is required to ensure we meet our performance and fault detection requirements under the Amended Bushfire Mitigation Regulations;
- some HV underground cable failures are likely to occur; and
- a number of existing assets appear resilient to the operation of a REFCL (e.g. high voltage (**HV**) insulators and distribution transformers).

3.2.2 Other distributors' REFCL trials

AusNet Services and United Energy have also conducted trials of REFCLs on their networks. These trials include the following:

- arc ignition mitigation testing of the Swedish Neutral’s Ground Fault Neutraliser (**GFN**) in United Energy’s Frankston South zone substation in 2014;
- installation of a REFCL in AusNet Services’ Kilmore South zone substation in 2015, where we actively participated in the program; and
- installation of a REFCL in AusNet Services' Woori Yallock zone substation.

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[6] The required capacity is defined in the Amended Bushfire Mitigation Regulations.

The learnings from these trials appear consistent with our experience. For example, the installation of a REFCL in AusNet Services' Woori Yallock zone substation demonstrated the need for significant network hardening works (including the risk of HV cable failures).

3.2.3 International trials

REFCLs have been installed in parts of Europe and New Zealand. However, as recognised by Marxsen Consulting in their report for DEDJTR (in preparation of their RIS), REFCL manufacturers have developed their products focused on European conditions that are completely different to those which apply in Australia.[7]

Unlike in Victoria, for example, REFCLs installed internationally have not been operated as a means to reduce bushfire risks. Similarly, no other country has mandated REFCLs to be installed with the required capacity (i.e. sensitivity) as set out in the Amended Bushfire Mitigation Regulations.

The international experience with REFCLs is further discussed in section 5 (on reliability impacts).

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[7] Marxsen Consulting, *REFCL Trial: Ignition Tests*, 4 August 2014, p. 88.

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4 Regulatory requirements

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Under the Rules, a distributor may apply to the AER during a regulatory control period to amend a distribution determination that applies to that distributor where a trigger event for a contingent project in relation to that distribution determination has occurred.[8] It is not until the predefined trigger event occurs that the AER undertakes a detailed examination of the efficient costs required to satisfy the capital expenditure factors.[9]

Contingent projects are also subject to a materiality test. The materiality test requires the costs exceed the greater amount of $30 million or five per cent of the value of the annual revenue requirement for the relevant distributor for the first year of the relevant regulatory control period.[10]

This section demonstrates how the trigger event and materiality thresholds have been met. It also discusses the relevant criteria and factors the AER must have regard to when assessing the efficient costs included in a contingent project application.

4.1 Trigger event

In its final decision for our 2016–2020 regulatory control period, the AER defined the trigger event that must occur for the AER to consider our contingent project application. This trigger event was defined as follows:[11]

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

Each of these components is discussed below.

4.1.1 Bushfire mitigation plan accepted by Energy Safe Victoria

Consistent with the *Electricity Safety Act 1998* (**the Act**), Powercor maintains a BMP that is approved by ESV.[12] Our BMP sets out our bushfire mitigation program for asset inspection, maintenance, construction, upgrading,

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8 NER, cl. 6.6A.2.

9 AER, *Final decision, Powercor distribution determination 2016 to 2020, Attachment 6 – Capital expenditure, May 2016*, p. 6–128.

10 NER, cl. 6.6A.1(2)(iii).

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

12 See section 113A(1) of the Electricity Safety Act 1998.

replacement, vegetation management, performance monitoring and auditing. It applies to assets that could cause fire ignition in all areas of our network.

Following consultation with ESV, in December 2016 we submitted an updated BMP that listed our proposed REFCL installation program for the 2016–2020 regulatory control period. The inclusion of these works followed amendments to the Amended Bushfire Mitigation Regulations, as set out in section 2.3.

On 21 December 2016, ESV approved our updated BMP.[13] This meets part (i) of the trigger event set out in the AER's final decision.

4.1.2 Capital expenditure forecast

Our forecast of costs for each REFCL included as part of this contingent project application is set out in our attached expenditure build-up model. This meets part (ii) of the trigger event set out in the AER's final decision.

The structure of our expenditure build-up model reflects our detailed functional design scopes, and the assumptions underpinning our forecasts are discussed in detail in section 6.

4.1.3 Project scopes

Our functional design scopes for each individual REFCL project have been included as part of this contingent project application. This meets part (iii) of the trigger event set out in the AER's final decision.

Our functional design scopes were developed consistent with our normal business processes.

4.2 Materiality threshold

The materiality test requires the proposed contingent capital expenditure exceeds the greater amount of $30 million or five per cent of the value of the annual revenue requirement for the relevant distributor for the first year of the relevant regulatory control period.[14] The proposed contingent capital expenditure and five per cent of our annual revenue requirement for 2016 are set out in table 4.1.

Table 4.1 Assessment of materiality threshold ($m, $2015)

Assessment criteria	Expenditure
Proposed contingent capital expenditure	$87.1
Five per cent of our annual revenue requirement in 2016	$28.7

Source: Powercor, *Expenditure build-up model*, March 2017

As shown in table 4.1, our proposed contingent capital expenditure exceeds $30 million (and also exceeds five per cent of our annual revenue requirement in 2016).

For clarity, our contingent project application also includes our forecast of incremental operating expenditure associated with the rollout of REFCLs for tranche one. Incremental operating expenditure is explicitly allowed for

[13] Powercor, *Bushfire Mitigation Plan, Revision 3.1*, 5 December 2016.

[14] NER, cl. 6.6A.1(b)(2)(iii).

under the Rules, however, it is not considered in the determination of whether the materiality threshold has been met.[15]

4.3 Assessment of efficient costs

Under the Rules, where the trigger event and materiality threshold have been met, the AER must accept our forecast capital and operating expenditure for the contingent project if it is satisfied the amount of forecast capital and operating expenditure reasonably reflects the capital and operating expenditure criteria, taking into account the capital and operating expenditure factors.[16]

The capital expenditure criteria requires the total capital expenditure forecast reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.[17]

The capital expenditure objectives includes the total forecast expenditure required to maintain the quality, reliability and security of supply of standard control services, and to maintain the safety of the distribution system through the supply of standard control services.[18]

[15] See, for example: NER, cl. 6.6A.2(b)(3) and 6.6A.2(e).

[16] NER, cl. 6.6A.2(f)(2).

[17] NER, cl. 6.5.7(c)(3).

[18] NER, cl. 6.5.7(3)(iii) and cl. 6.5.7(4).

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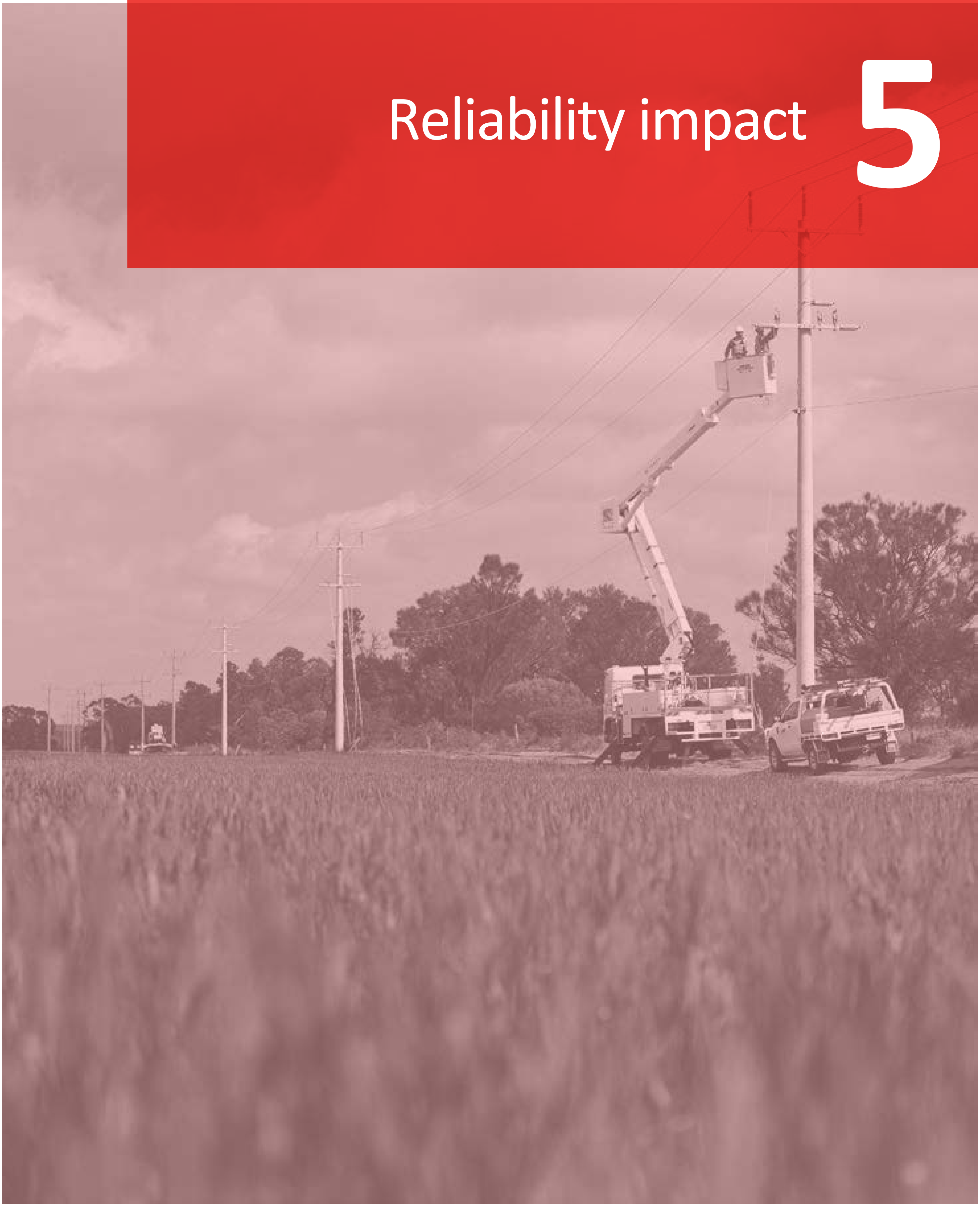
5 Reliability impact



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The reliability impact of operating REFCLs in our network will be primarily driven by our required operating mode, and the existing configuration of our network. This section outlines our operating mode and network configuration, and discusses expected qualitative reliability impacts (including a response to the reliability assumptions set out in the RIS published by the DEDJTR).

At this time, however, the overall impact on reliability from installing and operating REFCLs is uncertain.

We also outline the expected impact of operating a REFCL on our guaranteed service level (**GSL**) liabilities, and the f-factor scheme.

5.1 Operating mode

The Amended Bushfire Mitigation Regulations do not specify a required operating mode for REFCLs. Instead, our operating regime is set out in our BMP, approved by ESV in December 2016.

Our approved BMP outlines three potential operating modes—fire risk mode, normal mode and bypass mode. These modes are summarised in table 5.1:

Table 5.1 REFCL operating modes

Operating mode	Operational process
Fire risk mode	• When a fault is detected the REFCL compensates immediately • Waits a few seconds before performing a 'soft' fault confirmation test • If the fault is gone (transient), remove compensation • If the fault is permanent, trip the faulted feeder at the circuit breaker and remove compensation
Normal mode	• When a fault is detected the REFCL compensates immediately • Waits a few seconds before performing a 'classic' fault confirmation test • If the fault is gone (transient), remove compensation • If the fault is permanent, trip the faulted feeder at the circuit breaker or ACR and remove compensation
Bypass mode	• When a fault is detected the REFCL compensates immediately • Waits a few seconds before performing a soft fault confirmation test • If the fault is gone (transient), remove compensation • If the fault is permanent, bypass the REFCL increasing the fault current allowing protection devices to isolate the fault through normal discrimination (as per status quo)

Source: Powercor

Notes: A soft fault confirmation test elevates the faulted phase voltage in a controlled fashion to identify any changes in earth current with respect to the neutral voltage changes. In contrast, a classic fault confirmation test increases the faulted phase voltage in a less gradual manner.

These operating modes provide different levels of bushfire mitigation protection, as well as varying reliability impacts. ESV has stated its expectation that we operate REFCLs to optimise both safety and reliability outcomes, but with a primary focus on safety. ESV also stated that any impact on reliability must be material for it to entertain an arrangement that reduces a safety outcome.[19]

Our approved BMP requires us to operate REFCLs in fire risk mode on total fire ban (**TFB**) days with the best available sensitivity. Fire risk mode provides the greatest benefit in terms of reducing the risk of fire starts.

Our BMP also states our intention to trial the operation of REFCLs as follows:

[19] ESV, *Administration of Electricity Safety (Bushfire Mitigation) Amendment Regulations 2013 by Energy Safe Victoria*, 14 September 2016.

- in fire risk mode for the full fire season (i.e. for the six month period between October and March);
- in normal mode on low fire risk days; and
- in bypass mode on non-TFB days when fire risk mode and normal mode are not deployed.

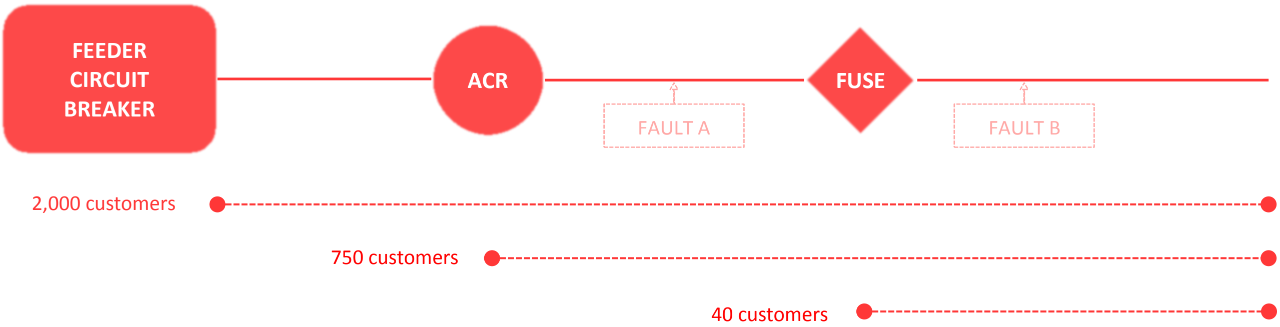
Our BMP states the most likely reason for not employing an operating mode in accordance with our stated intention would be unexpected adverse reliability impacts, storm events and/or unpredictable performance of the REFCL. In approving our BMP, ESV recognised the new and uncertain nature of the REFCL technology. We expect our operating mode (and ESV's expectations) will evolve over time as we integrate the technology and develop a better understanding of the impact of operating REFCLs on our network.

5.2 Network configuration

Our existing network is configured to utilise protection devices, such as ACRs and fuses, to segment our network into isolatable sections. This allows us to manage network outages safely, and to minimise reliability impacts to our customers.

The operation of a REFCL, however, is designed to function before downstream protection devices have the opportunity to operate. When operated in fire risk mode, for example, if the REFCL identifies a permanent fault it trips the feeder at the circuit breaker (as opposed to allowing our downstream ACRs and fuses to respond). As shown in the simplified example in figure 5.1 and table 5.2, the impact on reliability of operating REFCLs in fire risk mode therefore depends on the relative locations of protection devices and customers on each feeder.

Figure 5.1 Simplified example of protection devices



Source: Powercor

Table 5.2 Example of reliability impacts from operation of REFCLs

Example	No REFCL	REFCL operating (fire risk mode)
Fault A: downstream of ACR	ACR operates: 750 customers off supply	C/B trips: 2,000 customers off supply
Fault B: downstream of fuse	Fuse operates: 40 customers off supply	C/B trips: 2,000 customers off supply

Source: Powercor

5.3 Expected reliability impact

The operation of REFCLs in our network is expected to have reliability impacts on both momentary and sustained outages.

Momentary outages

Once REFCLs are operational, we expect some improvement to our Momentary Average Interruption Frequency Index (**MAIFI**). This is because REFCLs should provide compensation until transient earth faults have cleared, resulting in fewer momentary outages.

Any improvement in MAIFI outcomes will occur irrespective of our operating mode.

Sustained outages

The expected reliability impact on sustained outages is driven by two opposing influences:

- a material increase in sustained outage duration and frequency when REFCLs are operated in fire risk mode. As previously noted, REFCLs are designed to operate more quickly than our existing protection devices, resulting in the feeder tripping at the circuit breaker. This will cause material increases in SAIDI and SAIFI because:
  - additional customers will be impacted (i.e. customers located upstream of existing protection devices will be off supply, as the feeder will now trip at the circuit breaker);
  - it will take longer to identify the fault location (i.e. as the circuit breaker trips, downstream protection devices and fault indicators cannot be used to 'narrow' the location of a fault);
  - it will take longer to restore supply (i.e. under fire risk mode on a TFB day, crews are required to patrol the line prior to restoration of supply); and
  - more faults are expected to be identified, as the fault detection technology on resonant networks is more sensitive than on neutral-earthed networks.
- a potential decrease in sustained outage duration and frequency when REFCLs are operated in any mode, due to the potential reduction in asset damage associated with line interference (e.g. REFCLs have arc suppression coils which will suppress arc flares when there is intermittent contact with the line, for example, due to contact by animals and/or tree).

The increases in sustained outages from operating in fire risk mode are more certain and more material than any potential decrease in sustained outages expected due to avoiding consequential asset damage. Notably, we have no data or experience on which to quantify any potential reduction in asset damage. Further, the more frequently we operate REFCLs in fire risk mode (i.e. the greater number of TFB days that occur), the greater the expected detriment to our reliability performance in terms of sustained outages. These negative impacts will be exacerbated for customers on long feeders.

Accordingly, we expect an increase in sustained outages (SAIDI and SAIFI) from operating REFCLs.

Overall STPIS impact

Overall, we expect to experience a decline in reliability due to the operation of REFCLs on our network in fire risk mode. Any improvement in MAIFI outcomes will be more than offset by the deterioration in SAIDI and SAIDI outcomes (noting that MAIFI receives a lower incentive rate under the STPIS compared with sustained outages).[20]

[20] As outlined in the AER's STPIS guideline, the MAIFI incentive is only eight per cent of the SAIFI incentive.

These outcomes are summarised in table 5.3. For completeness, this table also shows the corresponding impact for alternative operating modes (noting that in relative terms, fire risk mode provides the greatest benefit in terms of reducing the risk of fire starts).

Table 5.3 Reliability impact of REFCL operating mode

Operating mode	MAIFI	SAIDI	SAIFI
Fire risk mode	Reduce	Increase	Increase
Normal mode	Reduce	Increase	Increase
Bypass mode	Reduce	No change	No change

Source: Powercor
Note: The SAIDI and SAIFI increases for normal mode are lower in magnitude than fire risk mode. Under fire risk mode, both ACRs and fuses are not operated, whereas under normal mode, only fuses are not operated.

Notwithstanding the above, consistent with the AER's reasons in its final decision for our 2016–2020 regulatory control period, we have not forecast any reliability adjustment to our contingent project expenditure allowances associated with our tranche one REFCL sites—for example:

- we plan to commission our tranche one REFCL sites from April 2018 at the earliest, in preparation for the 2018–2019 bushfire season. That said, we are only required to ensure REFCLs are operational and meet the required capacity by April 2019 (and April 2021 for EHK)—as set out in our approved BMP, there are many reasons we may experience delays to our planned commissioning timeline;
- the magnitude of any reliability impact is uncertain, as we have limited experience installing and operating REFCLs in our network, and international experience of using REFCLs has not focused on operating modes aimed at reducing bushfire starts; and
- any reliability impacts are dependent on our operating mode, and this mode may change prior to the commissioning of our tranche one REFCLs (e.g. as our experience with operating REFCLs grows, ESV may require our operating mode be expanded beyond TFB days).

We expect to further engage with stakeholders on this issue as part of developing our regulatory proposal for the 2021–2025 regulatory control period (when greater certainty is available regarding any reliability impacts).

5.4 Response to RIS

The RIS stated we should expect a 30 per cent improvement in the duration of sustained outages for phase-to-ground faults, which equates to a 21 per cent improvement in the overall duration of sustained outages.[21] These conclusions are contrary to our expectations discussed in section 5.3 (i.e. we expect declining reliability performance due to more frequent and longer sustained outages).

The RIS provides limited transparency regarding the assumptions, calculations and supporting information used to validate the claimed percentage improvements. In particular, it is not clear what operating mode is assumed in the RIS.

21 ACIL Allen Consulting, *Regulatory Impact Statement, Bushfire Mitigation Regulations Amendment*, 17 November 2015, p. 79.

Additionally, although the RIS acknowledges the detrimental impacts on sustained outages resulting from the technical design of REFCLs, it does not attempt to quantify these impacts. Given the network configuration at our tranche one REFCL sites, this negative impact may be significant. For example, a fault at the end of CLC06 (i.e. a long rural feeder with a history of outages) may now impact over 2,700 customers, as opposed to approximately 100 customers if our existing protection devices functioned.

The RIS also draws on the REFCL trial at Frankston South zone substation, and references to overseas studies, such as that undertaken by Auckland University. For the reasons set out below, we consider the Frankston South trial and Auckland University study provide insufficient basis on which to draw conclusions on the expected reliability impact on our network from operating REFCLs.

5.4.1 Frankston South zone substation

The REFCL at Frankston South was not required to operate at the capacity specified in the Amended Bushfire Mitigation Regulations. Operating at this specified capacity is likely to lead to deterioration in reliability.[22]

The Frankston South zone substation is also not representative of the zone substations on our network where REFCLs are required to be installed. In particular, the network configurations differ as follows:

- the average 22kV feeder length of our REFCL zone substations is 839km. In contrast, the average feeder length for United Energy (including their Frankston South zone substation) is 100km; and
- Frankston South serves a predominantly urban and semi-urban environment, whereas our zone substations are predominately in rural locations, and exposed to a wider variety of environmental and terrain conditions.

The results of the Frankston South trial were reported over the period from November 2013 to November 2014. Any improvements in reliability, therefore, were captured over a very short period of time and may reflect seasonal influences. A longer sample period is needed to infer confidence in any conclusions.

Further, distributors have numerous maintenance and reliability improvement programs in place, and these may be implemented in parallel with the introduction of a REFCL. On this basis, it is difficult to attribute any quantifiable reliability improvements to one single initiative.

5.4.2 Auckland University study

In 2012, a study undertaken by Auckland University observed a 62 per cent improvement in SAIDI from the operation of REFCL technology at the 11kV Poroti zone substation in New Zealand. For the reasons below, the results of this study should be interpreted with caution:

- the REFCL compensation period used in New Zealand, as well as other overseas countries that operate REFCLs, is longer than currently proposed in Victoria (i.e. they were installed for purposes other than bushfire mitigation, and as such, adopt a different operating mode to that set out in our approved BMP).[23] It would appear the REFCL in Poroti was operated with compensation on until the fault was found (although for clarity, we were unable to find any direct reference to the length of compensation in the report);

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22 ACIL Allen Consulting, *Regulatory Impact Statement, Bushfire Mitigation Regulations Amendment*, 17 November 2015, p. 79.

23 Extended compensation following the detection of a fault would involve the REFCL applying compensation and increasing voltages on the remaining healthy conductors for an extended period of time (e.g. eight hours). Although customers would remain on-supply while the fault condition exists and the REFCL applies compensation, there are important safety implications.

- after the REFCL was installed the total number of faults detected increased significantly. This increase can be attributed to the increased sensitivity of the REFCL protection system (i.e. events previously not detected were now being detected);
- the annual number of sustained faults per year also increased, although the basis for this was not explained;
- the number of phase-to-ground faults increased as a percentage of total faults after the installation of the REFCL—from around 32 per cent prior to the installation of the REFCL to around 93 per cent after; and
- the reliability data supplied showed a significant increase in SAIFI in the year of commissioning.

5.5 Guaranteed Service Level scheme impacts

We are required to make guaranteed service level (**GSL**) payments to customers who experience reliability that is worse than specified performance thresholds. Our operating expenditure allowances for the 2016–2020 regulatory control period are based on the average of GSL liabilities over 2010 to 2014 (adjusted for the new thresholds and rates determined by the Essential Services Commission on 23 December 2015).

As discussed in section 5.3, the operation of REFCLs in fire risk mode is expected to result in an increase in sustained outage frequency and duration. Consequently, we expect a corresponding increase in our GSL liabilities.

Given the uncertainty regarding the REFCL operating mode and consequential reliability impacts, and the timing for commencing the operation of our tranche one REFCLs, we do not propose any adjustments to the contingent project expenditure allowances for GSL liabilities at this time.

5.6 F-factor scheme impacts

The f-factor scheme provides a financial incentive for distributors to mitigate the risk of fire starts. The operation of REFCLs is expected to reduce the risk of fire starts in high bushfire risk areas.

On 22 December 2016, the Victorian Government amended the f-factor scheme to, amongst other things, account for the impact on the risk of fire starts from operating REFCLs. The amended f-factor scheme reduced our Ignition Risk Unit (**IRU**) target by 55.2 IRUs from the 2019–2020 financial year.[24]

The reduction in the IRU target is based on modelling undertaken by CSIRO for the Victorian Government. We are unable to validate the assumptions or modelling undertaken by CSIRO because we have not been provided this information.

Notably, the Victorian Government states that:

- the modelling takes into account our scheduled installation of REFCLs; and
- it is confident in the modelling results and it considers the level of adjustment fair.[25]

No further adjustments to the f-factor scheme or the contingent project allowance are therefore required to account for the operation of REFCLs reducing the risk of fire starts in high bushfire risk areas.

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[24] Victorian Government Gazette, *National Electricity (Victoria) Act 2005, F-Factor Scheme Order 2016*, 22 December 2016. The 2019–2020 IRU target applies to subsequent years unless the Minister publishes new IRU targets by Gazette.

[25] DELWP, *Powerline Bushfire Safety Program, f-factor incentive scheme, Statement of Reasons for Decision to Make Order in Council*, 14 December 2016.

6 Forecast expenditure

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Our forecast expenditure is based on our functional design scopes for each REFCL project (included as attachments REFCL.01 to REFCL.06). These scopes reflect the variability in the characteristics of each REFCL site. An overview of these characteristics, and their expenditure impact, is set out in table 6.1.

Table 6.1 Expenditure impact of site variability (existing site characteristics)

Expenditure driver	CDN	CLC	CMN	MRO	WIN	EHK
Customer numbers Customer numbers impact balancing requirements, control room operations and commissioning costs	5,717	16,584	11,473	9,504	3,337	15,376
Surge arrestor sites Surge arrestor sites are a key labour driver (noting three phase replacements require more labour than single phase) and also impact traffic management	1,933	2,467	2,054	1,665	736	2,021
ACR volumes ACR models that are not compatible with the operation of a REFCL network need to be replaced	9	19	5	9	3	10
Network capacitance (A) Network capacitance is a driver of the number of GFNs required to be installed at each zone substation	64	182	111	74	336	174
Total route length (km) Total route length impacts capacitive balancing requirements	918	1,323	906	946	479	936
Remote-controlled switching sections Three phase balancing requirements are primarily driven by the sections of our network bounded by remote-controlled switching devices	31	28	20	21	7	15
Number of feeders Commissioning costs are impacted by the number of feeders	5	7	5	6	3	8
Number of HV customers Isolation substations are required at each HV customer point of connection	2	9	5	-	-	9

Source: Powercor

Several other network characteristics also drive the variability in expenditure across our REFCL sites, including the underlying design of existing zone substations (which impacts primary and secondary plant requirements).

The following sections provide more detail on why key works are required as part of our REFCL projects. This includes the relevant substation and feeder works, as well as justification for the labour and contract rates used for these works.

Our forecast expenditure is also supported by our expenditure build-up model for each individual REFCL project (included as attachment REFCL_MOD.01).

6.1 Substation works

The installation of a REFCL requires changes to the electrical operating characteristics of a zone substation. These zone substation works include the installation of a GFN itself, as well as corresponding primary and secondary plant.

6.1.1 Ground fault neutraliser

The Amended Bushfire Mitigation Regulations require that each polyphase electric line originating from a selected zone substation has the 'required capacity'. The required capacity is defined as the ability to provide the following, in the event of a phase-to-ground fault on a polyphase electric line:

- 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;
- 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:
  - 1,900 volts within 85 milliseconds;
  - 750 volts within 500 milliseconds; and
  - 250 volts within 2 seconds;
- during diagnostic tests for high impedance faults, to limit:
  - fault current to 0.5 amps or less; and
  - the thermal energy on the electric line to a maximum I^2t value of 0.10.[26]

The above requirements can only be met through the use of REFCL technology—specifically, by migrating our existing systems to a resonant earthed network through the installation of a GFN. A GFN measures the shift in neutral voltage in response to an earth fault, and injects additional compensation current to reduce the faulted phase voltage to near zero. This allows the GFN to reduce earth fault current levels at a fault site to near zero.

The number of GFNs required at any zone substation is driven by a range of factors, including total system capacitance. Total system capacitance is itself a function of overhead line and underground cable length (noting the capacitance of underground cable is an order of magnitude more than 40 times that of overhead lines).

We estimate a single GFN can support the required performance standards to a maximum total system capacitance of approximately 130A. This range has been developed with input from the REFCL technical working group (**TWG**), and is discussed in detail in the attached technical document—implementation and optimisation of REFCL systems.[27]

As shown in table 6.2, the total system capacitance exceeds 130A at our CLC, WIN and EHK zone substations. Accordingly, these sites require two GFN units. This is consistent with the analysis set out by Marxsen Consulting

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[26] I^2t means a measure of the thermal energy associated with the current flow, where I is the current flow in amps and t is the duration of current flow in seconds.

[27] The Technical Working Group includes Dr Tony Marxsen, and representatives from Energy Safe Victoria (**ESV**) and each of the Victorian electricity distribution businesses. The purpose of the Technical Working Group is to facilitate the provision of technical advice, deployment and operations of REFCL technology across Victoria.

in their report for DEDJTR. Specifically, Marxsen Consulting stated that to achieve performance standards, some substations supplying larger networks may have to be fitted with multiple REFCLs.[28]

Table 6.2 GFN requirements relative to line/cable length

Network characteristic	CDN	CLC	CMN	MRO	WIN	EHK
Total system capacitance (A)	64	182	111	74	336	174
Underground cable (km)	-	35	18	4	114	44
Overhead line (km)	918	1,288	888	942	365	892
GFNs required	**1**	**2**	**1**	**1**	**2**	**2**

Source: Powercor

Alternative solutions to multiple GFNs were also considered, but are uneconomic. For example, avoiding the need for additional GFNs would require substantial additional undergrounding works, as well as additional isolation substations (both of which are high cost).

The extensive existing underground network at WIN, however, allowed us to avoid installing a third GFN at this zone substation. A third GFN at WIN would have also required significant investment in corresponding primary plant, including a third transformer. Instead, two GFNs and two isolation substations represented the least-cost technical acceptable alternative (to meet the performance specification requirements). For clarity, these two capacitance isolation substations are separate to the isolation substations required to maintain compliance for HV customers (i.e. they are required irrespective of the compliance issue discussed in section 6.2.6).

6.1.2 Other primary plant, and protection and control

The installation of a GFN requires consequential primary plant, and protection and control at each zone substation. Primary plant includes, for example, station service transformers and capacitor banks. Protection and control includes, for example, relay and protection equipment at the zone substation, and SCADA and communications infrastructure.

Our primary plant, and protection and control requirements are driven by the existing design of each zone substation, as well as whether multiple GFNs are required (e.g. our CLC, WIN and EHK zone substations). These requirements are set out in our expenditure build-up model, and are further discussed in the functional design scopes for each site.[29]

Attachments REFCL.07 and REFCL.08 also set out the design options considered for our CLC and WIN zone substations. Substantive alternative design options were not considered for EHK (even though multiple GFNs are required), as the existing design and layout at EHK already envisaged future conversion to fully-switchable configuration. Any relevant design considerations, therefore, are captured in the EHK functional design scope.

[28] Marxsen Consulting, *REFCL Technologies Test Program – Final Report*, 4 December 2015, p. 26.

[29] For clarity, our labour estimate for our primary plant works (as shown in our expenditure build-up model) is included in the labour volume forecast for installing our GFNs.

CLC zone substation

The installation of multiple GFNs requires the zone substation be capable of being split at the 22kV bus level into two separate segments (i.e. the zone substation must be fully switchable). This allows each GFN to provide the required capacity, as set out in the Amended Bushfire Mitigation Regulations.

Network segmentation at the zone substation is achieved through the use of circuit breakers within a switchyard (or indoor switch room). The installation of additional circuit breakers at our CLC zone substation, however, is complicated due to existing physical constraints at the site. That is, there is insufficient space to install multiple GFNs and corresponding switching capability without expanding or re-designing the site.

As set out in attachment REFCL.07, we considered several design options to ensure the least-cost technically acceptable solution was determined. The recommended option includes the installation of an indoor switch room for the additional circuit breakers and the relocation of the existing capacitor bank and 66kV line.

WIN zone substation

Our WIN zone substation also requires multiple GFNs to be installed to meet our regulatory obligations. As noted previously, this requires additional circuit breakers and switch rooms to be installed.

Our WIN zone substation is not subject to the same space constraints as CLC. The existing design of WIN, however, does not include a 22kV switchyard or many of the required protection and control devices. The recommended option for WIN includes the installation of an indoor switchboard on the north-east side of the site. Alternate design options are discussed in attachment REFCL.08.

6.2 Feeder works

Our feeder works reflect network hardening and compatibility expenditure to replace any assets on our network that are expected to fail or malfunction under the operation of a REFCL. This expenditure includes the following:

- surge arrestor replacements;
- ACR replacements;
- capacitive balancing requirements;
- distribution switchgear replacements; and
- HV cable replacements.

We have also included the installation of isolation substations at all HV customer connection points to ensure we maintain compliance with the *Electricity Distribution Code*.

6.2.1 Surge arrestor replacement program

For an earth fault on a resonant network, full voltage displacement of healthy phases occurs on a system wide scale. Full voltage displacement, irrespective of the time period, may result in voltage levels that exceed the notional capacity of our existing surge arrestors. For example, many of our existing surge arrestors have a maximum continuous operating voltage of 20kV, with limited temporary over-voltage capacity. During REFCL operation, the full phase-to-ground voltage is elevated up to 24.2kV for periods in excess of 30 seconds.

The failure of a surge arrestor to withstand over-voltages arising from the operation of a REFCL would induce a cross-country fault on the distribution system. This will result in multiple feeder outages, and potential fire starts.

Options for replacing surge arrestors

Our existing fleet of surge arrestors includes a range of brands and in turn, a variety of models. The replacement of all surge arrestors on feeders served by a zone substation where a REFCL is being installed represents a significant cost. Our REFCL project, therefore, proposes to only replace surge arrestors based on the following:

- surge arrestors with known operating characteristics that are not compatible with REFCL installations will be replaced (i.e. if the rated voltage is less than 24.2kV);
- surge arrestors with large populations of unknown and unverifiable specifications to be subjected to sample testing (to determine rated voltage). Surge arrestor families will be replaced if the sample fails any of the following tests:
  - one-hour 24kV soak test to verify rated voltage of a surge arrestor has not degraded with in-service age;
  - incremental voltage test from 22kV to 30kV to determine the rated voltage at which the surge arrestor transitions from capacitive range (blocking) to ohmic range (conducting or clamping). The minimum acceptable threshold prior to commencement of transition from capacitive to ohmic range (the knee point of the V-I characteristic) is a proxy for rated voltage;
  - thermal monitoring during 24kV soak test (in absence of a 22kV to 30kV incremental voltage test) to determine if surge arrestor has entered ohmic range, as indicated by a rise in temperature above ambient due to increased I^2R losses; and
- surge arrestors with small populations of unverified data specifications to be replaced (as the cost of obtaining sample assets and undertaking tests will be uneconomic relative to the cost of replacing these assets).

The above criteria, including our testing approach, were subject to an independent review undertaken by GHD.[30] GHD supported our surge arrestor replacement strategy.

GHD also reviewed our application of these criteria to our surge arrestor population. As set out in GHD's final report, our testing program found only the following types of surge arrestor installed on our network are capable of withstanding the higher voltages expected during the operation of a REFCL:

- type A: Bowthorpe porcelain silicon carbide (22kV and 24kV); and
- type W: ABB polim D polymeric zinc oxide, class A 22kV.

To identify these surge arrestors on feeders served by our tranche one zone substations, we engaged independent contractors to complete location-specific field audits (e.g. walking the length of each feeder and visually identifying non-compliant surge arrestor sites). The surge arrestors being replaced across each REFCL site (based on these field audits, and an estimate for EHK) is shown in table 6.3.[31]

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30 GHD, *Review of Powercor surge arrester replacement strategy*, March 2017.

31 Field audits for EHK are scheduled to be undertaken by July 2017. The figures included in table 6.3, therefore, are estimates based on data maintained in our SAP system. We will provide the AER with actual estimates for EHK once these become available.

Table 6.3 Surge arrestor sites

Surge arrestors	CDN	CLC	CMN	MRO	WIN	EHK
Surge arrestor sites (existing)	1,933	2,467	2,054	1,665	736	2,021
Surge arrestor sites (replacements)	736	1,426	1,330	914	361	1,512

Source: Powercor
Note: The figures shown above include single and three phase sites. The labour hours required to replace single and three phase sites differs, and accordingly, these costs are captured separately in our expenditure build-up model.

To limit the total replacement costs of our surge arrestor program, we also considered the following approaches proposed in the RIS published by the DEDJTR:[32]

- only replacing surge arrestors when they fail, either through stress testing or over time; and/or
- rationalising the number of surge arrestors installed, for example, by connecting surge arrestors in a 'Neptune' formation (i.e. where one new surge arrestor is connected in series with three existing surge arrestors).

We considered the above alternatives in the development of our functional design scopes. We rejected these options for the following reasons:

- the failure of a surge arrestor has the potential to start a bushfire, and as such, a reactive replacement program for a fleet of assets that are highly likely to fail is not considered prudent;
- a reactive replacement approach would result in the loss of labour and purchasing efficiencies;
- a reactive replacement approach would reduce our supply reliability due to the unplanned, reactive nature of addressing failed surge arrestors (e.g. this is supported by the New Zealand experience, whereby insufficient hardening works were undertaken prior to commissioning);
- rationalising the number of surge arrestors installed in our network would result in less protection across our network—consistent with the Rules, the introduction of a REFCL should not degrade the existing service level we provide to our customers;[33]
- connecting surge arrestors in a 'Neptune' formation is often not possible given the physical constraints of existing structures (e.g. pole mounted transformers, cable-head poles and gas switches); and
- the design and site rework required to connect surge arrestors in a 'Neptune' formation would likely exceed, or at best be cost neutral, compared to simply replacing all three existing arrestors with appropriately rated units.

6.2.2 ACR replacement program

ACRs and gas switches are used on electrical distribution feeders radiating from zone substations to divide feeders into sections that can be de-energised without impacting other parts of our network. The configuration of ACRs on our network is discussed in section 5.2.

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32 ACIL Allen Consulting, *Regulatory Impact Statement - Bushfire Mitigation Regulations Amendment*, 17 November 2015, pp. 69-70.

33 NER, cl. 6.5.7(a)(3)(iii).

Our expenditure forecast includes the replacement of two specific models of ACRs (i.e. RVE and VWVE), as well as control box upgrades for a limited number of our remaining ACRs and remote controlled gas switches. These devices do not have the capability to measure the direction of current flows.

With a REFCL in operation, increased earth fault currents will occur on a faulted feeder. At the same time, the REFCL will also increase earth fault currents flowing on all other un-faulted feeders. To avoid tripping these un-faulted feeders, our ACRs must be able to measure the direction of current flow—that is, these ACRs must detect the difference between actual fault currents and the increased current flow from the operation of a REFCL. This requirement was recognised by Marxsen Consulting in their report to DEDJTR:[34]

> *… many earth fault protection systems on Victorian networks are non-directional... Using non-directional feeder earth fault relays with a REFCL in service will lead to tripping of healthy feeders or whole groups of feeders… This may be a major challenge as many ACRs do not have the voltage measurement components required for directional earth fault protection.*

The volume of our existing and replacement ACRs, as well as required ACR control box upgrades, are shown in table 6.4. Our gas switch control box upgrade volumes are shown in table 6.5.

Table 6.4 ACR replacements and control box upgrades

Volumes	CDN	CLC	CMN	MRO	WIN	EHK
Existing ACRs	9	19	5	9	3	10
RVE and VWVE ACRs (replacement volume)	4	4	1	1	-	3
ACR control box upgrades	-	13	3	6	-	2

Source: Powercor

Table 6.5 Gas switch upgrades

Volumes	CDN	CLC	CMN	MRO	WIN	EHK
Existing remote controlled gas switches	3	28	-	-	2	2
Gas switch control box upgrades	2	4	-	-	-	1

Source: Powercor

6.2.3 Capacitive balancing

Resonant HV distribution networks—such as those used to operate a REFCL—are acutely sensitive to capacitive imbalances.[35] Imbalanced phase-to-ground currents, for example, lead to increased neutral voltage levels.[36] As

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[34] Marxsen Consulting, *REFCL Trial: Ignition Tests*, 4 August 2014, p. 94.

[35] Capacitance exists on any energised apparatus in an electrical system. Capacitance arises from the air between the overhead line and ground, or the insulation between underground cable cores and the cable sheath (noting that underground cable has approximately 40 times the amount of capacitance of overhead line). Capacitive imbalances on our existing network have typically been managed through reducing the sensitivity of traditional protection to low-level earth faults.

[36] Neutral voltage is the voltage measured at the star point of the network at the substation, at which the REFCL is connected.

neutral voltage levels are used to detect whether an earth fault exists on a resonant network, excessive neutral voltages may trigger a fault response from a REFCL even when a fault does not exist.[37]

The Amended Bushfire Mitigation Regulations reflect the need for balanced capacitance. That is, the Amended Bushfire Mitigation Regulations require:

- a REFCL be capable of detecting high impedance faults with a resistance value in ohms equal to twice the nominal phase-to-ground network voltage.[38] For our 22kV polyphase distribution network, this requires a fault resistance of 25,400 ohms; and
- during diagnostic tests for high impedance faults, the capacity to limit fault current to 0.5A.

The operation of Swedish Neutral's GFN control system also requires each feeder be well balanced to allow its fault detection algorithm to operate effectively and to the performance specification (i.e. the algorithms require high levels of sensitivity to ensure the GFN can identify the feeder where a fault has occurred).

In order to achieve the operational sensitivity set out in the Amended Bushfire Mitigation Regulations, and meet the operating requirements of the GFN, our functional design scopes include the following required works:

- install single-phase admittance balancing units for every 300m of single-phase underground cable;
- perform overhead re-phasing works for every 15km of single-phase overhead line;
- install three-phase admittance balancing units between remote-controlled switching sections, as well as between strategically located manually-operated isolatable sections;
- install fuse savers for any fused sections with overhead line length greater than 9km; and
- upgrade HV regulators to closed delta configurations with parallel control.

Admittance balancing units and re-phasing works

Admittance balancing units are used to provide supplementary capacitance to cater for imbalances on particular feeders. As outlined previously, the effective operation of a REFCL is highly sensitive to capacitive imbalances.

Our balancing approach utilises a combination of single phase and three phase balancing units, as well as re-phasing works on overhead lines, to meet the required fault resistance of 25,400 ohms and limit fault current during testing to 0.5A. Single phase balancing units and re-phasing are rigid, low cost measures that resolve large, static imbalances. Three phase balancing units provide tuning functionality (i.e. flexibility) that allows us to more accurately balance capacitance, and to respond to variability in our capacitive balancing requirements over time.

Single phase balancing units and re-phasing

Our forecast of single phase balancing units and re-phasing requirements is driven by the length of single phase line and cable. We propose to install single phase balancing units for every 300m of single phase underground cable, and undertake re-phasing works for every 15km of single phase overhead line. This is consistent with our GSB and WND experience for balancing units, and reflects a less conservative approach for re-phasing (i.e. at GSB and WND, we initially performed re-phasing works every 5.6km).

[37] An earth fault is where a conductor makes contact with something earthed (e.g. the ground, trees, cross-arms). This results in a neutral voltage in a resonant network.

[38] High impedance faults are defined in the Amended Bushfire Mitigation Regulations.

Three phase balancing units

Our network is currently configured with remote-controlled and manually-operated switches along our feeders. These switches provide isolatable sections that allow operational flexibility to reconfigure our network for planned maintenance, to permanently transfer loads, or to isolate faults.

Maintaining our existing level of network switching flexibility (and therefore reliability performance) would require the installation of three phase balancing units within each isolatable section. This represents over 1,700 three phase balancing units. Given the costs of such an approach, we have not proposed this option.

Instead, we only propose to install three phase balancing units between remote-controlled switching sections, as well as between strategically located manually-operated isolatable sections. These strategic locations reflect existing isolatable sections with high customer density and/or long line length.

A summary of our admittance balancing unit and re-phasing requirements is set out in table 6.6

Table 6.6 Admittance balancing units and re-phasing requirements

Volumes	CDN	CLC	CMN	MRO	WIN	EHK
Isolatable sections (existing)	259	520	303	221	130	294
Remote-controlled switching sections (existing)	31	28	20	21	7	15
Re-phasing sites	42	46	34	39	14	36
Admittance balancing units (single phase)	2	9	8	3	12	8
Admittance balancing units (three phase)	41	42	30	33	13	31

Source: Powercor

Re-balancing works (i.e. re-phasing and tuning three phase balancing units) are also undertaken on an annual basis. This is consistent with our requirement under the Amended Bushfire Mitigation Regulations to ensure, before the specified bushfire risk period each year, our network can operate to meet the required capacity in relation to each polyphase electric line.[39] These annual works are set out in section 6.7.

Fuse savers

The operation of a REFCL only responds to phase-to-ground faults (i.e. earth faults). For all other faults, we rely on 'traditional' protection mechanisms.

For example, when a phase-to-phase fault occurs on our three phase network, the fuses on the two corresponding phases will open. As the third phase remains energised, this will result in a large capacitive imbalance. In turn, as recognised in the RIS, this capacitive imbalance may trigger fault responses from a REFCL on feeders where a fault does not exist (i.e. 'healthy' feeders).[40]

To resolve this issue, fuse savers operate to ensure that when a phase-to-phase fault occurs, all phases on the impacted section of line are de-energised (and hence, the capacitance imbalance on healthy feeders is avoided).

39 Electricity Safety (Bushfire Mitigation) Regulations 2013, Authorised version no. 004, cl. 7(1)(hb).

40 ACIL Allen Consulting, *Regulatory Impact Statement, Bushfire Mitigation Regulations Amendment*, 17 November 2015, p. 79.

Similar to our three phase balancing unit requirements, we have not forecast the installation of fuse savers for every fuse installed on our 22kV network. Instead, our expenditure build-up model includes the installation of fuse savers for any fused section with overhead line length greater than 9km.

This distance is the calculated maximum line length that can be asymmetrically disconnected and not result in neutral voltage imbalances that would trigger a fault response from the REFCL. The calculated maximum line length is based on the parameters in table 6.7. The basis for these parameters is set out in detail in attachment REFCL.09—the implementation and optimisation of REFCL systems.

Table 6.7 System requirement parameters

Parameter	Value	Comments
Network capacitance	111A	Mid-point of range of maximum network capacitance per GFN
Damping resistance	2.5 %	Existing damping resistance observed on our network
Fault resistance	25,400Ω	As required in Amended Bushfire Mitigation Regulations
Minimum operating voltage	1,600V	Minimum operating voltage required to detect fault resistance
Maximum standing neutral voltage	320V	Maximum allowable voltage caused by standing capacitive imbalances

Source: Powercor, *Implementation and optimisation of REFCL systems*, March 2017.

HV regulator upgrades

Historically, our network has been designed using an 'open-delta' configuration for HV regulators. This approach has traditionally been regarded as the lowest cost option to regulate voltages on long rural feeders.[41]

An open-delta configuration, however, inherently creates a capacitive imbalance. As the operation of a REFCL is particularly sensitive to capacitive imbalances, HV regulator upgrades are required. Specifically, a third transformer is required to be added to 'close' the delta. This remedial approach was supported by Marxsen Consulting in their report to DEDJTR.[42]

We are also upgrading control boxes at existing closed-delta HV regulators to ensure these regulators operate in unison (to prevent capacitive imbalances).

6.2.4 Distribution switchgear replacements

Distribution switchgear installed throughout our network provides the functionality to reconfigure our network for operational requirements, fault response, and general maintenance. The failure of distribution switchgear will result in feeder faults and corresponding wide-spread outages.

The existing distribution switchgear on our network includes a range of models. The resilience assessment undertaken at GSB and WND found these models to be largely resilient to elevated REFCL phase-to-ground voltages. The exception, however, is our 24kV Felten and Guilleaume (**FG**) switchgear.

Prior to our network stress testing and commissioning processes, we undertook resilience assessments on selected distribution plant assets (typically older assets with a heightened risk of failure). For our FG switchgear,

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41 Marxsen Consulting, *REFCL Trial: Ignition Tests*, 4 August 2014, p. 94.

42 Marxsen Consulting, *REFCL Trial: Ignition Tests*, 4 August 2014, p. 94.

this assessment was to ensure these assets could withstand elevated voltages up to 24kV for a period of 30 minutes. The resilience assessment of our FG switchgear confirmed a limitation of 20.8kV—that is, the FG switchgear was unable to meet the required elevated voltages (let alone withstand these voltages for a period 30 minutes).

The failure of the FG switchgear cannot be addressed by modification or maintenance to the asset as the failure is due to inherent design and construction factors—these units are hermetically sealed SF6 pressurised welded tanks. The only technically feasible option, therefore, is the replacement of these assets.

We have nine FG units currently in service on our HV network for our tranche one sites (including four serviced by our CLC zone substation, two at CMN, and three at EHK). Our expenditure build-up model includes expenditure to replace these FG units on a like-for-like basis.

6.2.5 HV cable replacement

HV cable is installed throughout our network in a range of different specifications. We propose to undertake a proactive replacement approach for selected HV aerial bundled cable (**ABC**), and a reactive replacement approach for underground HV cable that fails.

HV ABC replacement

Non-metallic screened HV ABC is a particular cable standard installed in limited volumes on our network by the State Electricity Commission of Victoria. Over time, this cable has been found to be prone to 'pitting' of the outer insulation sheath that protects the HV ABC.

Cable-pitting typically occurs when sheath leakage currents arc to the catenary cable, and the insulation sheath is eroded. This leads to unpredictable operation of non-metallic screened HV ABC as the pitting allows, for example, water ingress to the cable. The failure of non-metallic screened HV ABC may culminate in the complete di-electric failure of the cable insulation.

The over-voltages that will occur with the operation of our REFCLs will accelerate the failure of our non-metallic screened HV ABC. Specifically, raising the phase-to-ground voltage by a factor of 1.73 increases the electrical stress at the points where the insulation has been weakened due to cable pitting.

In total, our network includes approximately 6km of non-metallic screened HV ABC. Our expenditure build-up model for our REFCL program includes the replacement of approximately 1.4km of non-metallic screened HV ABC at CDN and CLC. Our other tranche one sites (including GSB and WND) do not have any non-metallic screened HV ABC installed.

The unit rate for HV ABC replacements is consistent with previous overhead HV cable replacements undertaken as part of the Victorian Government's Powerline Replacement Fund.

Underground HV cable replacement

HV cable encases conductor within layers of insulation such that the cable can be buried underground. Underground HV cable failures typically occur when this insulation is compromised—for example, at cable joints or terminations.

Our approach to identifying underground HV cable replacement is a reactive process. That is, we will only replace underground HV cable that fails during network stress testing undertaken as part of our commissioning process.

During the commissioning process at GSB, our network stress testing resulted in the failure of sections of underground HV cable. This demonstrates that, notwithstanding a notional 22kV rating, these cables may still fail due to the over-voltages from the REFCL installation.

Given our experience at GSB, we have included a forecast of underground HV cable replacements in our contingent project application. The forecast is based on our actual repair costs (on a per meter basis), and the percentage of underground HV cable that actually failed. The percentage failure rate, however, has been moderated to exclude recent undergrounding works (e.g. undertaken as part of the Powerline Replacement).

6.2.6 HV customers (isolation substations)

The *Electricity Distribution Code* (**the Code**) requires we maintain a prescribed nominal voltage level at the point of supply to customers' electricity installations.[43] The Code also permits variations to these limits, with the extent of these variations decreasing as the time period increases.[44]

The testing and operation of REFCLs on our network will lead to breaches of the Code—for example, although the Code permits phase-to-earth voltage variations of 80 per cent for less than 10 seconds:

- stress testing undertaken during the commissioning of REFCLs requires increased phase-to-earth voltages of greater than 80 per cent, and for a period in excess of the time period set out in the Code; and
- when a REFCL is in operation, phase-to-ground over-voltages up to 190 per cent may arise.

Given the above, we requested the Essential Services Commission of Victoria (**ESCV**) amend the Code to better reflect the testing and operating characteristics of a REFCL, or to provide a letter of no-action regarding any such breaches.[45] The ESCV refused to grant a no-action letter, and only indicated that a review of the Code will be considered in its planning for 2017–2018.[46]

To maintain compliance with the existing Code, therefore, we propose to install isolation substations at the point of supply to all customers connected directly to our HV network. We currently have 52 customers directly connected to our 22kV network that would be impacted by our REFCL program (with 25 of these customers impacted by our tranche one REFCLs).

The required size of each isolation substation will vary for each customer, and is based on their measured maximum demand. These requirements are shown in table 6.8. The expenditure included for isolation substations in our expenditure build-up model reflects the total installation cost.

Table 6.8 Isolation substation requirements

Volumes	CDN	CLC	CMN	MRO	WIN	EHK
2 MVA substations	1	5	4	-	-	6
5 MVA substations	-	4	-	-	-	3
10 MVA substations	1	-	1	-	-	-
Total isolation substations	**2**	**9**	**5**	**-**	**-**	**9**

Source: Powercor

[43] Electricity Distribution Code, cl. 4.2.1.

[44] Electricity Distribution Code, cl. 4.2.2.

[45] AusNet Services and Powercor, *Electricity Distribution Code compliance and REFCLs*, 26 August 2016.

[46] ESCV, *Re: Electricity Distribution Code compliance and REFCLs*, 7 February 2017.

The installation of isolation substations will also remove the need for HV customers to undertake hardening works on their assets to ensure they are sufficiently rated to withstand REFCL over-voltages. These impacts were recognised in the RIS published by DEDJTR—for example:[47]

> *[w]hen a REFCL is installed, the earth "floats" rather than is "fixed". All equipment installed on the 22kV network must similarly have a "floating" earth, including equipment that is owned by customers that are connected directly to the 22kV network. This may require some equipment in a high voltage customer's substation to be replaced.*

The RIS stated the costs likely to be incurred by these customers were not known.[48] Individual customer costs, for example, will vary depending on the age, specification and quality of the equipment they have installed. As these works relate to private installations, our response to the RIS stated that customers would be required to fund these changes themselves.[49]

Given the costs of upgrading equipment are likely to have a significant impact on HV customers, it is appropriate for the AER to approve expenditure to allow us to install isolation substations at the connection point for each of our customers directly connected to our HV network. This will ensure the cost of upgrading equipment as a result of REFCL installation is borne by all customers, in the same way all customers benefit from reduced bushfire risk.

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

6.3 Removal of replacement expenditure

The AER's final decision for our 2016–2020 regulatory control period included a notional allowance for the replacement of existing assets on a business-as-usual basis, as estimated using its REPEX model. For example, the REPEX model forecast replacement volumes for surge arrestors and HV fuses on our network based on our historical replacement rates. [50] For these assets, the replacement rate was equal to approximately one per cent of our total surge arrestor and HV fuse population per annum. This replacement rate was multiplied by a unit cost to develop a total replacement expenditure allowance.

Our expenditure build-up model has applied the AER's replacement rate to our forecast surge arrestor replacement volumes, and multiplied this by the AER's unit cost (to determine the surge arrestor replacement component already funded by the AER's REPEX model). This amount was removed from our total forecast costs to avoid double-counting expenditure that is already funded.

We also adjusted our forecast expenditure to remove the AER's REPEX-funded total for ACR replacements. This approach is consistent with our inclusion of accelerated depreciation for surge arrestors and ACRs (as discussed in section 6.8.1).

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[47] ACIL Allen Consulting, *Regulatory Impact Statement - Bushfire Mitigation Regulations Amendment*, 17 November 2015, p. 72.

[48] ACIL Allen Consulting, *Regulatory Impact Statement - Bushfire Mitigation Regulations Amendment*, 17 November 2015, p. 72.

[49] Powercor, *Response to Regulatory Impact Statement, Bushfire Mitigation Regulations Amendment*, 30 December 2015, p. 18.

[50] For simplicity, the AER estimated replacement volumes for HV fuses and surge arrestor as a combined total.

6.4 Materials cost forecast

As discussed in sections 6.1 and 6.2, our REFCL project requires the procurement of a combination of high-volume, low-cost and low-volume, high-cost assets.

Our unit cost forecasts for the purchase of the majority of our primary plant and feeder works (including, for example, our GFNs, surge arrestors, balancing units and ACRs) are based on the corresponding prices incurred for our GSB and WND zone substations. Except for our GFN, the purchase of these assets followed our stringent procurement practices. This includes the bulk purchases of equipment (where practicable) and competitive tender processes.

A competitive tender was not undertaken for the purchase of our GFNs, as these units are only manufactured by Swedish Neutral (i.e. a sole supplier). Notwithstanding this, key contractual requirements were agreed to ensure the manufacturer is liable for the stated performance of each unit (e.g. warranty conditions and operational design assurances).

The forecast prices for our remaining plant reflect our previous experience purchasing and installing this equipment in the course of our normal operations. These purchase prices are estimated based on costs recorded in our SAP system.

6.5 Labour cost forecast

The key to ensuring labour cost efficiency is the efficient organisation and management of labour to minimise the risk of under-utilisation and under-performance. To achieve optimal labour utilisation, our labour force is structured to provide flexibility in managing labour resources. This includes the following types of labour contracts:

- internal labour—these are permanent employees who provide the base level of labour required to provide a base level of labour services. To operate sustainably over the long term we must ensure we have secure access to a sufficient quantity of labour with the skills and knowledge required to deliver the minimum level of network and corporate services;
- local service area (**LSA**) agents—these are third party owned and operated franchises that provide network services in specific network areas. LSAs service different locations across our network and are generally assigned in the lower density network areas. LSAs are selected through a five yearly market testing process;
- resource partners—these are third-party businesses, for example Lend Lease and Electrix, that provide additional labour services on an as needs basis. We utilise our resource partners to manage increased workloads that may arise for specific work programs. Resource partners are identified through a three yearly market testing process; and
- contractors—we utilise contractors for skill-specific work including electrical work, fault response, metering works, civil works (i.e. digging works), traffic management, design work and vegetation management. We have different contractual arrangements with our contractors, ranging from longer term contracts with third party businesses, such as Daly's Constructions Australia and Powercables, to project-specific arrangements with individual Registered Electrical Contractors.

We expect to utilise both resource partner and internal labour for the delivery of our REFCL program. The use of each labour source is discussed below.

For the purpose of this contingent project application, we have applied labour escalation based on the approach and escalators set out in the AER's final decision for our 2016–2020 regulatory control period.

6.5.1 Resource partners

For the following reasons, we expect to utilise labour provided by our external resource partners for the design and delivery of our required substation and feeder works:

- our internal and LSA labour resources are fully utilised on our existing capital program (as set out in our regulatory proposal for the 2016–2020 regulatory control period)—this reflects the contingent nature of our REFCL program;
- utilising resource partners and external contractors reduces the risk of labour stranding following large-scale or skill-specific projects; and
- our resource partner and external contractor rates are subject to stringent market tender processes. This includes open market offers, followed by qualitative assessments of their ability to perform the required works and quantitative assessments of the tendered rates.

Design

Our design labour rates represent a simple average of rates provided by our design resource partners. As noted above, these rates are the result of an open-market, competitive tender process.

The forecast design hours vary for each REFCL site based on the technical requirements and volumes set out in the individual functional design scopes.

Feeder and substation works

Our feeder and substation labour rates represent a simple average of rates provided by our delivery resource partners. These rates vary by region (e.g. Bendigo resource partner rates are used for CMN, MRO and EHK, and Colac rates for CDN, CLC and WIN). As noted above, these rates are the result of an open-market, competitive tender process.

The forecast feeder and substation hours vary for each REFCL site based on the technical requirements and volumes set out in the individual functional design scopes.

6.5.2 Internal labour

Our forecast of commissioning works, construction delivery and site control, and our project management office is based on internal resources. The basis for these forecasts is set out below.

Commissioning costs

Our commissioning process for each REFCL site begins by following Swedish Neutral's recommended commissioning plan to ensure each unit has been installed, wired and configured as required. Once these pre-commissioning checks have been completed, we will undertake the following:

- balancing unit tuning—this involves switching the 22kV network and tuning each balancing unit to ensure switching sections are individually balanced. This tuning allows us to increase the REFCL sensitivity so we can ensure we can achieve the required fault resistance of 25,400 ohms;
- stress testing—this involves switching on the REFCL and systematically applying over-voltages on each phase of our 22kV network. This replicates the same stress that our network assets will experience during the operation of our REFCL. As such, it confirms whether our network is appropriately hardened, or provides for any weakened or vulnerable equipment to fail and create a fault, assisting in location and replacement; and
- primary fault testing—this testing uses a portable earth fault test truck with a variable 22kV resistor to test our protection tripping schemes (to ensure the REFCL integration equipment operates as designed). That is, it tests the ability of the REFCL to meet the performance specification in terms of sensitivity and speed of

operation. In addition to commissioning, this testing is required to be undertaken annually, consistent with the approach set out in our approved BMP (and required under the Amended Bushfire Mitigation Regulations).[51]

The above tests are required to confirm we have met the performance requirements of the Amended Bushfire Mitigation Regulations. Further, if these tests were not undertaken, we would be unaware of the resilience of our network to the over-voltages that exist during the operation of a REFCL. This would greatly increase the risks of fire starts, have material reliability impacts, and make fault finding and restoration difficult.

Our commissioning works also include portable generation capacity, prior to isolation substations being operational, to minimise planned outages to HV customers over multiple consecutive days (on which testing is completed).

Our forecast of commissioning works is driven by the number of feeders, and accordingly, commissioning expenditure varies for each zone substation. The annual (ongoing) component of this forecast (i.e. the primary fault testing) is set out in section 6.7, and reflects the expected timing of our REFCL installation program set out in section 3.1.

Construction delivery and site control

Our construction delivery and site control works support the delivery of our REFCL projects to our required schedule, budget, and safety standards. These activities include, for example, the following:

- on-site management—given the size of this project, the short timeframes for completion, and our limited experience in the installation and use of REFCLs on our network, effective on-site delivery management is critical to controlling the construction process;
- project scoping—project scopes are required to be developed for all zone substation works and balancing requirements. This includes the management and collection of network data, and the development of business cases for more complex issues. These scopes are provided to external designers to develop job files and technical project design;
- project scheduling—our REFCL program requires integrated and flexible task allocation and scheduling (within and across sites) to maximise resource utilisation. This requires ongoing communication with field staff, construction managers, procurement, network planners and controllers, and external contractors;
- quality assurance—the sensitivity of our REFCLs to operational requirements and compliance obligations necessitates stringent quality assurance processes. This includes testing of equipment prior to installation and assurance that design specifications have been implemented. These activities minimise reactive replacements required during commissioning works (noting that reactive replacements are more costly than planned replacements for high volume processes, such as surge arrestor replacements); and
- occupational health, safety and environmental—includes site induction, and ongoing monitoring and reporting throughout our REFCL works to ensure we meet all our health, safety and environmental obligations.

Construction delivery and site control are directly attributable costs for each individual REFCL site. This reflects the delivery management and site control approach for our GSB and WND REFCLs, and is consistent with our typical budgeting methodology.

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[51] See section 6.5.1 of our BMP: Powercor, *Bushfire Mitigation Plan, Revision 3.1*, 5 December 2016.

Project management office

Our project management office expenditure includes our change management and training requirements, as well as incremental network, customer communications and regulatory resources.

We have forecast our project management office as a total for tranche one, and allocated these costs to each zone substation based on the percentage of construction costs per site relative to the total for tranche one. This forecast reflects the complexity and challenging timeframes of our REFCL programme.

Change management and training requirements

As outlined previously, a resonant network fundamentally changes how we operate parts our network. This necessitates the development of, and transition to, new operating processes—for example, new design, planning, control and maintenance standards; new procurement standards (for REFCL-specific and compatible assets); updated operating manuals; and required IT system and process changes. These processes ensure we maintain a safe operating environment for our staff, contractors and the community.

Our project management office expenditure also includes costs related to re-training staff to comply with amended operational procedures. This includes our general line workers, who will continue to maintain our network, as well as our network engineers and control room staff. These changes were recognised in our submission to DEDJTR in preparation of its RIS.[52]

Our training program will include all line workers at our Colac, Geelong and Bendigo depots, and the fitters and testers at our Bendigo and Ballarat depots. These staff will attend a day-long induction course on safe work practices for maintaining resonant HV distribution networks (noting that these depots will service the network where our REFCLs are being installed).

For clarity, line workers at our Kyneton depot, fitters and testers based at our Ardeer depot, and all of our control room staff have already undertaken the required training programs to understand the impact of operating a resonant HV distribution network.

Network, regulatory and customer communications resources

Our project management office includes the incremental resources required to operate a resonant network. This includes, for example, the following:

- project planning and governance oversight—we currently have limited experience with the installation of REFCLs throughout our network, and detailed project planning is required to manage this risk within the short delivery timeframes (particularly given the risk of substantial civil penalties associated with project delays). This includes ensuring overall project delivery and governance, as well as internal business and compliance reporting;
- technical support—installing and operating a GFN requires detailed technical knowledge and the provision of engineering support (both during the construction phase for our resource partners, and as a going concern for our network planning and operational requirements);
- network control—the installation and commissioning of a REFCL, and the corresponding hardening works, will result in high volumes of (incremental) planned outages. The complexity of the switching requirements is significant, and in combination with our business-as-usual maintenance requirements, cannot be achieved

52 Powercor, *Response to Regulatory Impact Statement, Bushfire Mitigation Regulations Amendment*, 30 December 2015, p. 16.

with our existing resource compliment. At GSB and WND alone, the control room job lots increased by 43 per cent due to the REFCL program; and

- customer communication and management—planned supply outages have significant impacts on the communities we serve (particularly our HV customers), and require ongoing customer liaison and support. This includes planned outage notifications—our GSB and WND customers received multiple notifications—and community awareness measures (such as notifications in local media).

Our REFCL program also requires incremental regulatory resources for the completion of our REFCL application and forecast modelling. This includes the provision of regulatory and legal advice regarding our compliance obligations.

6.6 Contract expenditure

In addition to the materials and labour costs outlined above, our REFCL program includes expenditure for third-party contracts that are competitively tendered—specifically, traffic management, line surveys and civil works. Our forecasts of these costs are based on the following:

- traffic management costs are driven by the volume of surge arrestors and fuse savers, and are consistent with the unit rate for our GSB and WND sites;
- line surveys were used to determine surge arrestor replacement volumes; and
- civil works reflect the requirements set out in our functional design scopes, and accordingly, these forecasts vary by site.

6.7 Forecast expenditure summary

A summary of our expenditure forecast for our tranche one REFCL sites is set out in table 6.9. This table includes project specific costs (both capitalised and expensed), as well as ongoing incremental operational expenditure.

Our approach to including incremental operating expenditure is consistent with the reasons set out in the AER's final decision for our 2016–2020 regulatory control period, whereby the AER accepted operating expenditure step changes driven by new regulatory obligations.

Table 6.9 Summary of total expenditure requirements ($m, nominal)

Forecast expenditure	2016	2017	2018	2019	2020
Project costs (capitalised)	-	50.9	40.1	-	-
Project costs (expensed)	-	2.2	2.2	-	-
Incremental re-balancing works	-	-	-	0.1	0.3
Incremental compliance testing	-	-	-	0.2	0.3
Incremental technical support	-	-	-	0.0	0.1
Total	**-**	**53.1**	**42.3**	**0.4**	**0.7**

Source: Powercor
Note: Tables may not add due to rounding

6.8 Forecast incremental revenue

Our forecast of incremental revenue has been developed using the AER's final decision post-tax revenue model (**PTRM**). For the purpose of this contingent project application, this includes, for example, the AER's final decision estimates for the rate of return (including gamma), standard lives and inflation. We have only updated the AER's final decision PTRM, therefore, to reflect the capital and incremental operating expenditure requirements summarised in section 6.7 (and the corresponding depreciation impact, discussed in section 6.8.1).

A summary of our forecast incremental revenue is set out in table 6.10.

Table 6.10 Summary of incremental revenue requirements ($m, nominal)

Building block components	2016	2017	2018	2019	2020
Return on capital	-	0.1	3.2	5.6	5.4
Return of capital (regulatory depreciation)	-	0.0	2.3	3.1	3.3
Operating expenditure	-	2.2	2.3	0.4	0.8
Net tax allowance	-	-0.0	0.3	0.3	0.4
Annual revenue requirement (unsmoothed)	-	2.2	8.2	9.5	9.9
Annual revenue requirement (smoothed)	**-**	**0.0**	**9.6**	**10.0**	**10.5**

Source: Powercor
Note: Tables may not add due to rounding

6.8.1 Accelerated depreciation

As set out in section 6.2.1 and section 6.2.2, the installation and operation of REFCLs on our network necessitates the removal of selected surge arrestors and ACRs. For the following reasons, the assets being removed are now redundant:

- the costs of transporting and storing old surge arrestors is uneconomic relative to the cost of purchasing a new surge arrestor;
- re-using existing surge arrestors would require an assessment of the condition of each asset and is uneconomic relative to the cost of purchasing a new surge arrestor;
- our RVE and VWVE ACRs do not meet our current technical installation standards; and
- our RVE and VWVE ACRs require dedicated structures, and building these structures (in addition to refurbishment costs) would be uneconomic relative to the cost of purchasing new ACRs.

Given the above, our incremental revenue requirement includes a forecast of the remaining undepreciated value of these assets. This does not change the total amount received in depreciation for these assets, though it does change the timing of receipt and the consequential return on capital.

The AER has previously accepted accelerated depreciation for assets that are no longer required. For example, in its final decision for our 2016–2020 regulatory control period, the AER accepted accelerated depreciation for two asset sub-classes—single wire earth return (**SWER**) ACRs and supervisory cables.[53]

SWER ACRS, in particular, were replaced based on the recommendations of the VBRC, and subsequent direction from ESV. The AER noted the following:[54]

> *[w]e consider that there is a regulatory requirement for Powercor to replace the Old SWER ACRs, imposed upon it by the Victorian Government. The replacement will be completed over the 2016–20 regulatory control period. Hence, the effective economic life of the assets is reduced and so we accept Powercor's proposal to change its depreciation schedule for these assets to align with the reduced economic life.*

We have forecast the remaining undepreciated value of the replaced surge arrestors and ACRs based on the approach we used for SWER ACRs (and accepted by the AER). As regulatory depreciation for these assets is not separately tracked, this approach includes a bottom-up estimate of the indicative initial cost for each asset, and calculating an implied depreciation based on the estimated age of each asset family.

[53] AER, *Final decision, Powercor distribution determination, 2016 to 2020, Attachment 5 – Regulatory depreciation*, May 2016.

[54] AER, *Preliminary decision, Powercor distribution determination, 2016 to 2020, Attachment 5 – Regulatory depreciation*, October 2015.

Attachment list A

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Table A.1 Attachment list

Attachment number	Title
REFCL.01	Powercor, *Functional design scope (CDN)*, March 2017
REFCL.02	Powercor, *Functional design scope (CLC)*, March 2017
REFCL.03	Powercor, *Functional design scope (CMN)*, March 2017
REFCL.04	Powercor, *Functional design scope (MRO)*, March 2017
REFCL.05	Powercor, *Functional design scope (WIN)*, March 2017
REFCL.06	Powercor, *Functional design scope (EHK)*, March 2017
REFCL.07	Powercor, *CLC zone substation options analysis*, March 2017
REFCL.08	Powercor, *WIN zone substation options analysis*, March 2017
REFCL.09	Powercor, *Implementation and optimisation of REFCL systems*, March 2017
REFCL.10	Powercor and AusNet Services, *Electricity Distribution Code compliance and REFCLs*, 26 August 2016
REFCL.11	ESCV, *Re: Electricity Distribution Code compliance and REFCLs*, 7 February 2017
REFCL.12	Powercor, *Bushfire Mitigation Plan, Revision 3.1*, 5 December 2016
REFCL.13	GHD, *Review of Powercor surge arrester replacement strategy*, March 2017

Table A.2 Model list

Model number	Title
REFCL_MOD.01	Powercor, *Expenditure build-up model (tranche one)*, March 2017
REFCL_MOD.02	Powercor, *Amended PTRM*, March 2017
REFCL_MOD.03	Powercor, *Amended depreciation model*, March 2017
REFCL_MOD.04	Powercor, *Amended REPEX model*, March 2017

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Compliance checklist B

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Table B.1 Compliance checklist

Rule provision	Requirement	Relevant section
Part C: Building block determinations for standard control services		
6.6A	Contingent Projects	
6.6A.2(a)	Subject to paragraph (b), a Distribution Network Service Provider may, during a regulatory control period, apply to the AER to amend a distribution determination that applies to that Distribution Network Service Provider where a trigger event for a contingent project in relation to that distribution determination has occurred.	Noted
6.6A.2(b)	An application referred to in paragraph (a):	Noted
6.6A.2(b)(1)	must not be made within 90 business days prior to the end of a regulatory year;	Noted
6.6A.2(b)(2)	subject to subparagraph (1), must be made as soon as practicable after the occurrence of the trigger event;	Noted
6.6A.2(b)(3)	must contain the following information:	Noted
6.6A.2(b)(3)(i)	an explanation that substantiates the occurrence of the trigger event;	Section 4.1
6.6A.2(b)(3)(ii)	a forecast of the total capital expenditure for the contingent project;	Section 4.2; REFCL_MOD.01
6.6A.2(b)(3)(ii)	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;	Section 6.7; REFCL_MOD.01
6.6A.2(b)(3)(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);	Section 4.2
6.6A.2(b)(3)(v)	the intended date for commencing the contingent project (which must be during the regulatory control period);	Section 3.1
6.6A.2(b)(3)(vi)	the anticipated date for completing the contingent project (which may be after the end of the regulatory control period);	Section 3.1
6.6A.2(b)(3)(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); and	Section 6.8; REFCL_MOD.02
6.6A.2(b)(4)	the estimate referred to in subparagraph (3)(vii) must be calculated:	Noted
6.6A.2(b)(4)(i)	in accordance with the requirements of the post-tax revenue model referred to in clause 6.4.1;	Section 6.8; REFCL_MOD.02
6.6A.2(b)(4)(ii)	in accordance with the requirements of the roll forward model referred to in clause 6.5.1(b);	Section 6.8; REFCL_MOD.02
6.6A.2(b)(4)(iii)	using the allowed rate of return for that Distribution Network Service Provider for the regulatory control period as determined in accordance with clause 6.5.2;	Section 6.8; REFCL_MOD.02

Rule provision	Requirement	Relevant section
6.6A.2(b)(4)(iv)	in accordance with the requirements for depreciation referred to in clause 6.5.5; and	Section 6.8; REFCL_MOD.02
6.6A.2(b)(4)(v)	on the basis of the capital expenditure and incremental operating expenditure referred to in subparagraph (3)(iii).	Section 6.8; REFCL_MOD.01
6.6A.2(i)	A Distribution Network Service Provider must provide the AER with such additional information as the AER requires for the purpose of making a decision on an application made by that Distribution Network Service Provider under paragraph (a) within the time specified by the AER in a notice provided to the Distribution Network Service Provider by the AER for that purpose.	Noted

Source: National Electricity Rules, version 89