Powercor

Contingent project application
REFCL program: tranche two

April 2018

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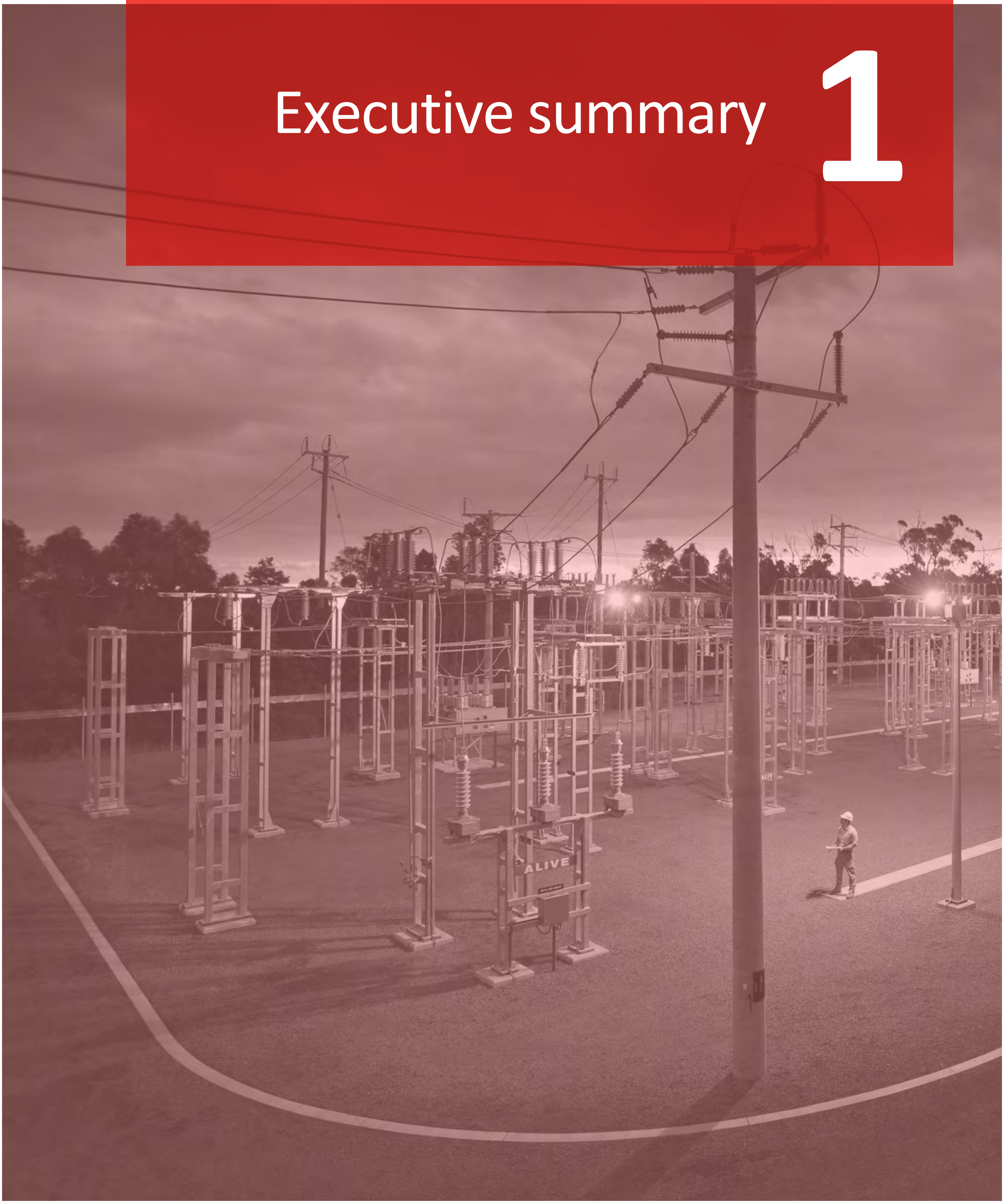
Contents

1 EXECUTIVE SUMMARY 5
2 BACKGROUND 9
2.1 Powerline Bushfire Safety Taskforce 11
2.2 Regulatory impact statement 12
2.3 Amended Bushfire Mitigation Regulations 12
2.4 Bushfire Mitigation Civil Penalties Scheme 12
3 OUR REFCL PROGRAM 13
3.1 Our REFCL tranches 15
3.2 Our experience in deploying REFCLs 15
3.3 Other trials 17
4 REGULATORY REQUIREMENTS 19
4.1 Trigger event 21
4.2 Materiality threshold 23
4.3 Assessment of efficient costs 24
5 KEY DIFFERENCES FROM TRANCHE ONE 25
5.1 Network characteristics 27
5.2 Balancing methodology 27
5.3 Underground cables replacement 29
5.4 Earth grids and current transformer replacements 30
5.5 GFN on a feeder 31
5.6 GFN enclosures 33
5.7 Testing trailer 33
5.8 Spare GFN 33
6 HV CUSTOMERS 35
6.1 Regulatory context 37
6.2 Approach to HV customers 37
6.3 High voltage customer assistance program 38
7 FORECAST EXPENDITURE 39
7.1 Substation works 42
7.2 Feeder works 44
7.3 Removal of replacement expenditure 51
7.4 Materials cost forecast 52

7.5 Labour cost forecast 52
7.6 Contract expenditure 57
7.7 Forecast expenditure summary 57
7.8 Forecast incremental revenue 58
A ATTACHMENT LIST 61
B COMPLIANCE CHECKLIST 65

Executive summary 1



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This is our second contingent project application to the Australian Energy Regulator (**AER**) seeking an amendment to our revenue allowance for the installation of Rapid Earth Fault Current Limiters (**REFCL**s) on our network.

REFCLs are required to be installed so that we comply with the amendments to the Electricity Safety (Bushfire Mitigation) Regulations 2013 (**Amended Bushfire Mitigation Regulations**) which were implemented in Victoria on 1 May 2016.

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 expenditure required to install REFCLs on our network was not included in our revenue allowance for the 2016–2020 regulatory control period. Instead, the AER's 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).

In August 2017, the AER made a final decision on our first application for the revenue allowance to be adjusted by $95.4 million ($nominal) for the installation of REFCLs in our network. The 'tranche one' expenditure related to:

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

This second application, referred to as 'tranche two', relates to the installation of REFCLs in a further six zone substations in our network, including the large regional cities of Ballarat, Bendigo and Geelong. Four of the six zone substations in this application serve over 25,000 customers, whereas the largest zone substation in our first tranche served just 16,500. This will be our largest and most complex tranche for REFCLs.

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

Table 1.1 Summary of incremental revenue requirements ($m, real 2015)

Building block components	2016	2017	2018	2019	2020	Total
Return on capital	-	0.1	0.1	5.0	8.2	13.3
Return of capital (regulatory depreciation)	-	0.0	0.0	5.3	6.9	12.2
Operating expenditure	-	0.0	3.2	2.6	0.6	6.4
Net tax allowance	-	-0.0	-0.0	0.7	0.7	1.4
Annual revenue requirement (unsmoothed)	-	0.0	3.3	13.6	16.4	33.3
Annual revenue requirement (smoothed)	**-**	**0.0**	**0.0**	**16.4**	**17.2**	**33.6**

Source: Powercor

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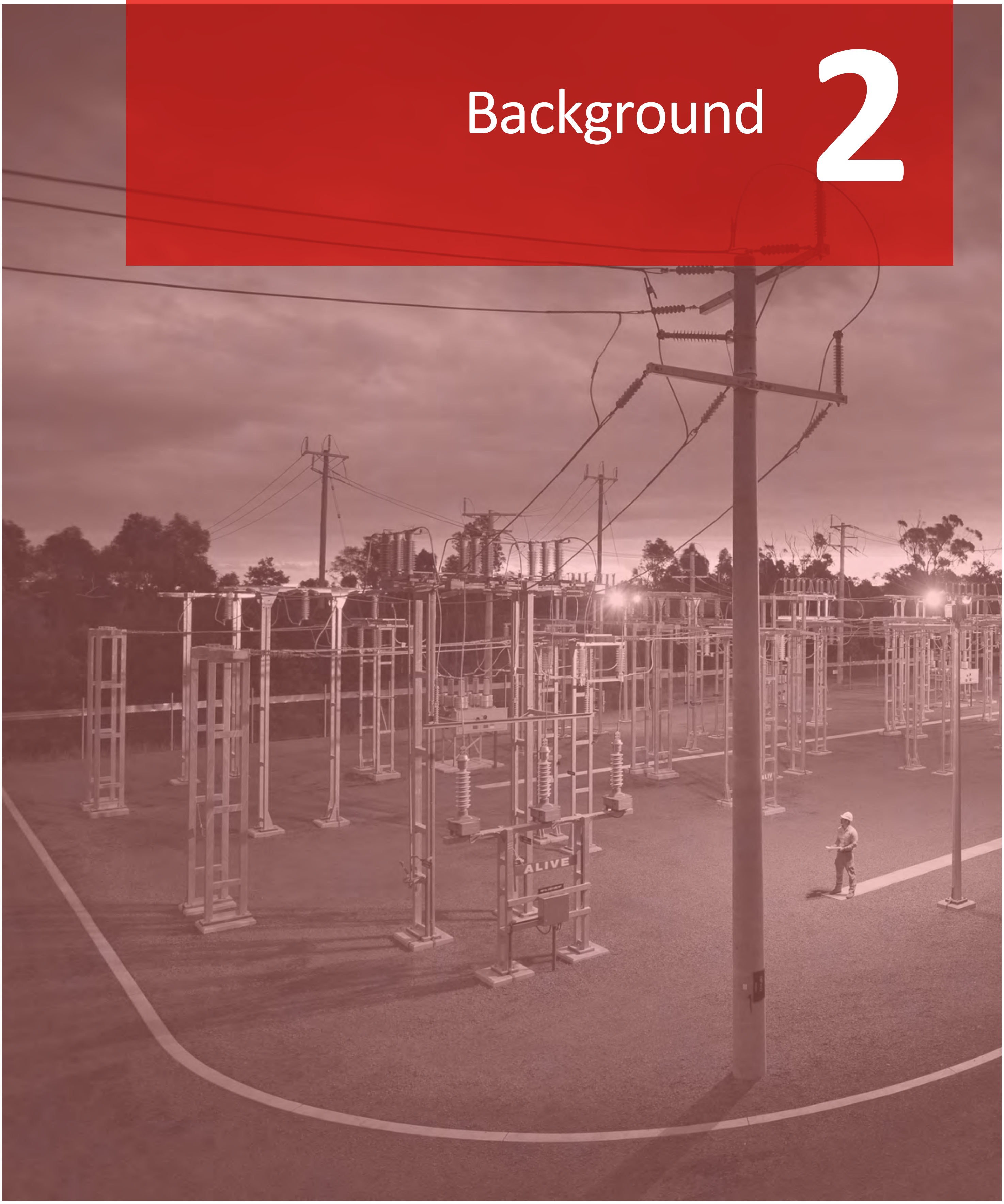
Background 2



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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
- the Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme).

Further background on the relevant regulatory requirements under the National Electricity Rules (**the Rules, or NER**) 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
- requiring powerlines in declared areas to be put underground or insulated.

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 introduced regulations which amended the *Electricity Safety (Bushfire Mitigation) Regulations 2013* (**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
- 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 16 May 2017, the Victorian Government introduced the Bushfire Mitigation Civil Penalties Scheme via an amendment to the Electricity Safety Act 1998. The 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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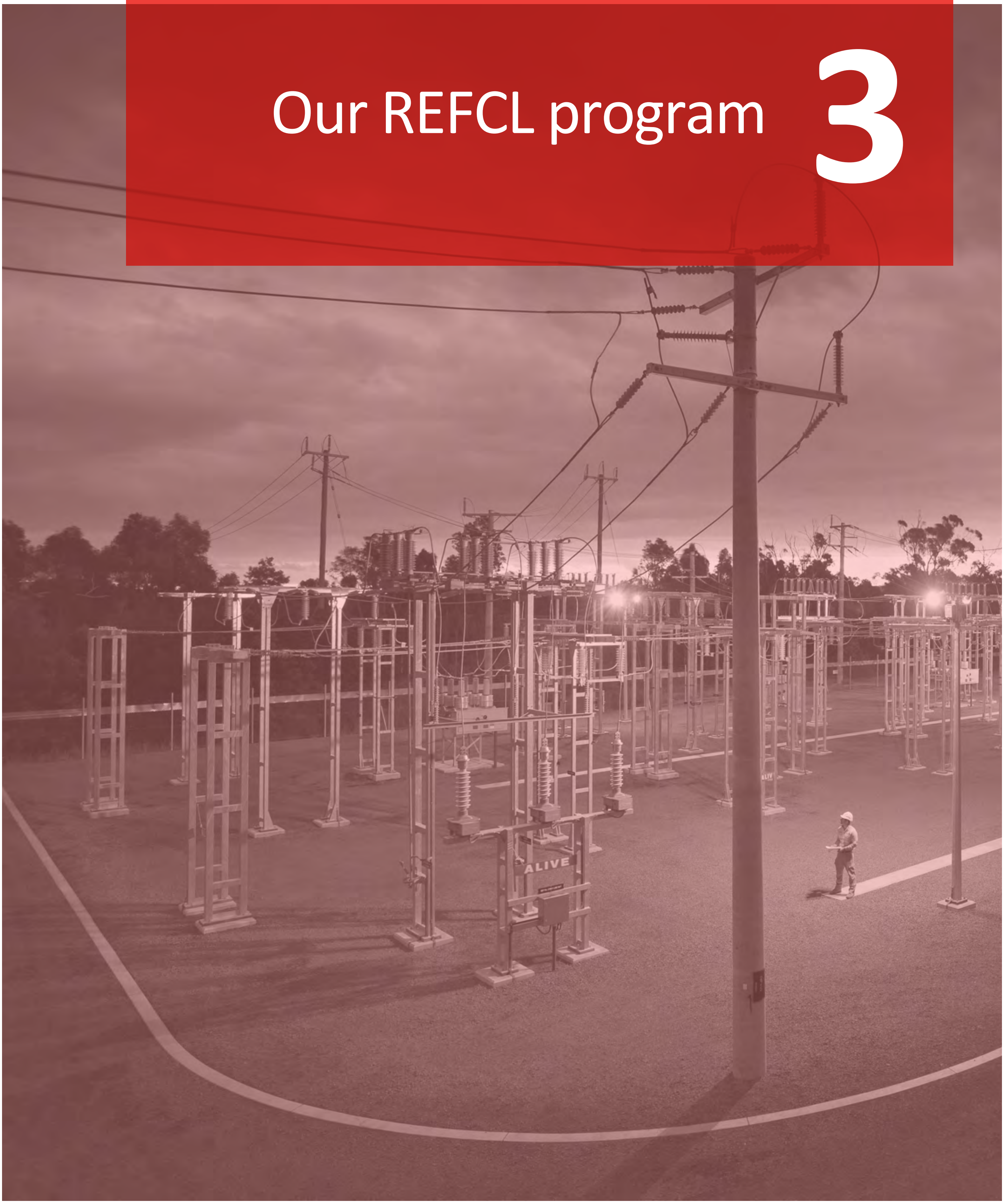
2 Powerline Bushfire Safety Taskforce, *Final report*, 30 September 2011, p. 5.

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 our experience to-date from commissioning REFCLs at Woodend and Gisborne and the rest of our tranche one deployment program. Where relevant, we also discuss trials and experiences undertaken by other Australian distributors as well as international experience.

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

Source: Powercor, Bushfire Mitigation Plan, Revision 4.1b, 29 March 2017, p. 20.

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

Table 3.1 REFCL installation timeframes: tranche two

REFCL site	Planned installation	Required capacity
Bendigo TS (**BETS**)	May 2020	April 2021
Charlton (**CTN**)	March 2020	April 2021
Bendigo (**BGO**)	April 2020	April 2021
Ballarat South (**BAS**)	April 2021	April 2021
Ballarat North (**BAN**)	March 2021	April 2021
Geelong (**GL**)	April 2021	April 2021

Source: Powercor, *Bushfire Mitigation Plan, Revision 4.1b*, 29 March 2017.

The zone substations set out in tranche three are expected to be included in a subsequent contingent project application.

3.2 Our experience in deploying REFCLs

We continue to learn about the deployment and operation of REFCLs from our trials at Woodend and Gisborne and the rest of tranche one. The key issues are set out below.

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 was separate to the tranche one contingent project application.

We successfully installed and commissioned the GSB zone substation with a single REFCL in October 2016. In May 2017, we consider that we met the performance requirements set out in the Amended Bushfire Mitigation Regulations (i.e. 'required capacity'), although we are awaiting confirmation from Energy Safe Victoria (**ESV**).[6] GSB is the newest Powercor zone substation, and was established in 2013.

We have installed two REFCL units at the WND zone substation, however further works and testing is required to achieve the required performance standard. We hope for this to be completed in mid-2018.

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 deployment at GSB and WND highlighted the following:

- achieving performance requirements may necessitate multiple REFCL units at particular zone substations
- the capacitive charging current of the network being protected should be kept to within 81 – 108A
- only selected surge arrestor 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
- a number of existing assets appear resilient to the operation of a REFCL (e.g. high voltage (**HV**) insulators and distribution transformers).

Additionally technical challenges have been experienced at WND. WND is an older zone substation compared to GSB, and more typical for the Powercor network. The particular challenges that we have faced includes:

- a large number of underground cable failures
- a change to the rebalancing approach
- inaccuracy of existing instrumentation transformers
- longer than expected timeframe for commissioning
- additional capacitance works and equipment required to meet the 'required capacity'.

3.2.2 Tranche one of our REFCL deployment program

We are obligated to achieve the required performance standards for REFCLs at all zone substations in tranche one by 1 May 2019. We are well progressed in our deployment plans for these zone substations.

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

A single REFCL has been installed at the Camperdown (**CDN**) zone substation, together with surge arrestor replacements and balancing works, with testing expected to be completed by June 2018. The surge arrestor replacements and balancing works have also been completed for Maryborough (**MRO**) and Castlemaine (**CMN**) zone substations. The installation of the REFCL and other associated works are expected to be completed at MRO and CMN by June 2018.

The Winchelsea (**WIN**), Eaglehawk (**EHK**) and Colac (**CLC**) zone substations will each have two REFCLs and associated equipment installed in the October to December quarter of 2018, with testing and commissioning required to be completed by 30 April 2019.

3.3 Other trials

3.3.1 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
- installation of a REFCL in AusNet Services' Woori Yallock zone substation.

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).

3.3.2 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.

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

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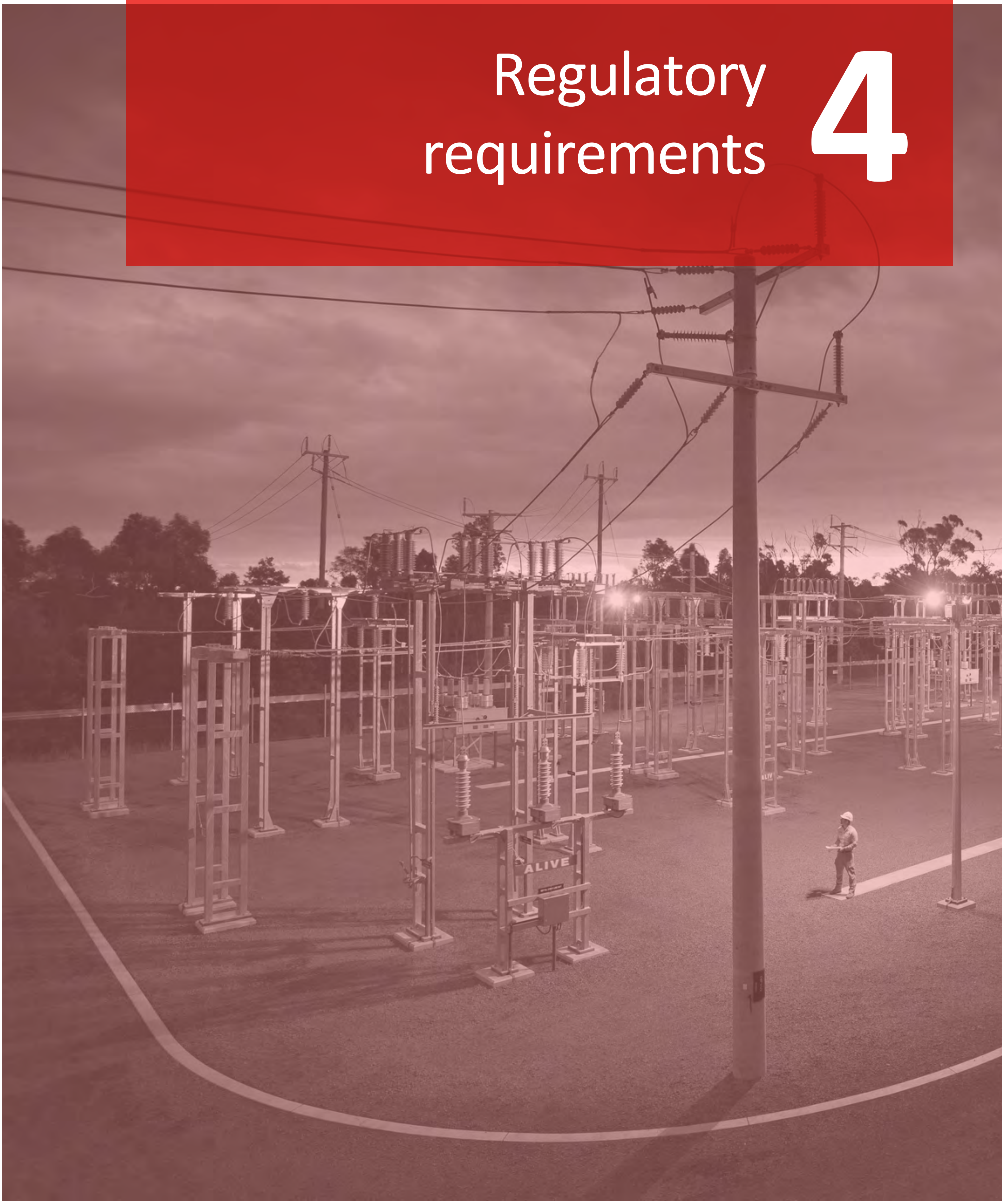
Regulatory requirements 4



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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.

In August 2017, the AER published its decision regarding our first contingent project application relating to the installation of REFCLs on our network. The AER's decision is also discussed in this section.

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 second 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;*
>
> *(iv) The AER has made a determination under clause 6.6A.2(e)(1) of the NER in respect of bushfire mitigation contingent project 1.*

Each of these components is discussed below.

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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*, pp. 6–144 to 6–145.

4.1.1 Bushfire mitigation plan accepted by Energy Safe Victoria

Consistent with the *Electricity Safety Act 1998* (**the Act**), Powercor maintains a bushfire mitigation plan (**BMP**) that is approved by ESV.[12] Our BMP sets out our bushfire mitigation program for asset inspection, maintenance, construction, upgrading, 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, 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 30 March 2017, ESV accepted 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 7.

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.

4.1.4 AER decision on first contingent project application

In August 2017, the AER published its decision in respect of our first contingent project application. This meets part (iv) of the trigger event set out in the AER's final decision.

The first contingent project application covered the installation of REFCLs in six zone substations, namely Camperdown (**CDN**), Colac (**CLC**), Castlemaine (**CMN**), Eaglehawk (**EHK**), Maryborough (**MRO**), and Winchelsea (**WIN**).

The AER found that the project as described was consistent with the contingent project approved in our 2016–2020 regulatory determination, that the trigger event had occurred, and that the capital expenditure sought exceeded the required threshold.

The AER approved the contingent project application but with modifications to the amounts sought. The amounts approved by the AER are shown in the table below.

---

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

13 Powercor, *Bushfire Mitigation Plan, Revision 4.1b*, 29 March 2017.

Table 4.1 Capital and incremental operating expenditure (real, $m 2015)

	2016	2017	2018	2019	2020	Total
Incremental capital expenditure	0.0	43.4	33.9	0.0	0.0	77.3
Incremental operating expenditure	0.0	2.11	2.11	0.33	0.67	5.2

Source: AER, Final Decision Powercor Australia Contingent Project Installation of Rapid Earth Fault Current Limiters (REFCLs) – tranche 1, August 2017, p. 64.

A key element of the AER decision related to the expenditure associated with isolating transformers for high voltage (**HV**) customers directly connected to the affected zone substations. The AER accepted that we are liable under the Victorian Electricity Distribution Code (**Distribution Code**) for adverse effects to HV customers as a consequence of REFCL operation. However, the AER found that the works associated with HV customers exceeded the prudent and efficient costs necessary to implement the projects, and deducted $10.2 million ($nominal) from the amount sought in our application.

The AER indicated that its decision relating to the installation of isolating transformers at HV customer sites, and capacitive loading issues at one zone substation was only applicable for our first tranche.

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 4.2.

Table 4.2 Assessment of materiality threshold ($m, real 2015)

Assessment criteria	Expenditure
Proposed contingent project capital expenditure	$127.7
Five per cent of our annual revenue requirement in 2016	$28.7

Source: REFCL2_MOD.01 Powercor, *Expenditure build-up model*

As shown in table 4.2, 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 two. Incremental operating expenditure is explicitly allowed for under the Rules, however, it is not considered in the determination of whether the materiality threshold has been met.[15]

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

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

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]

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).

Key differences from tranche one

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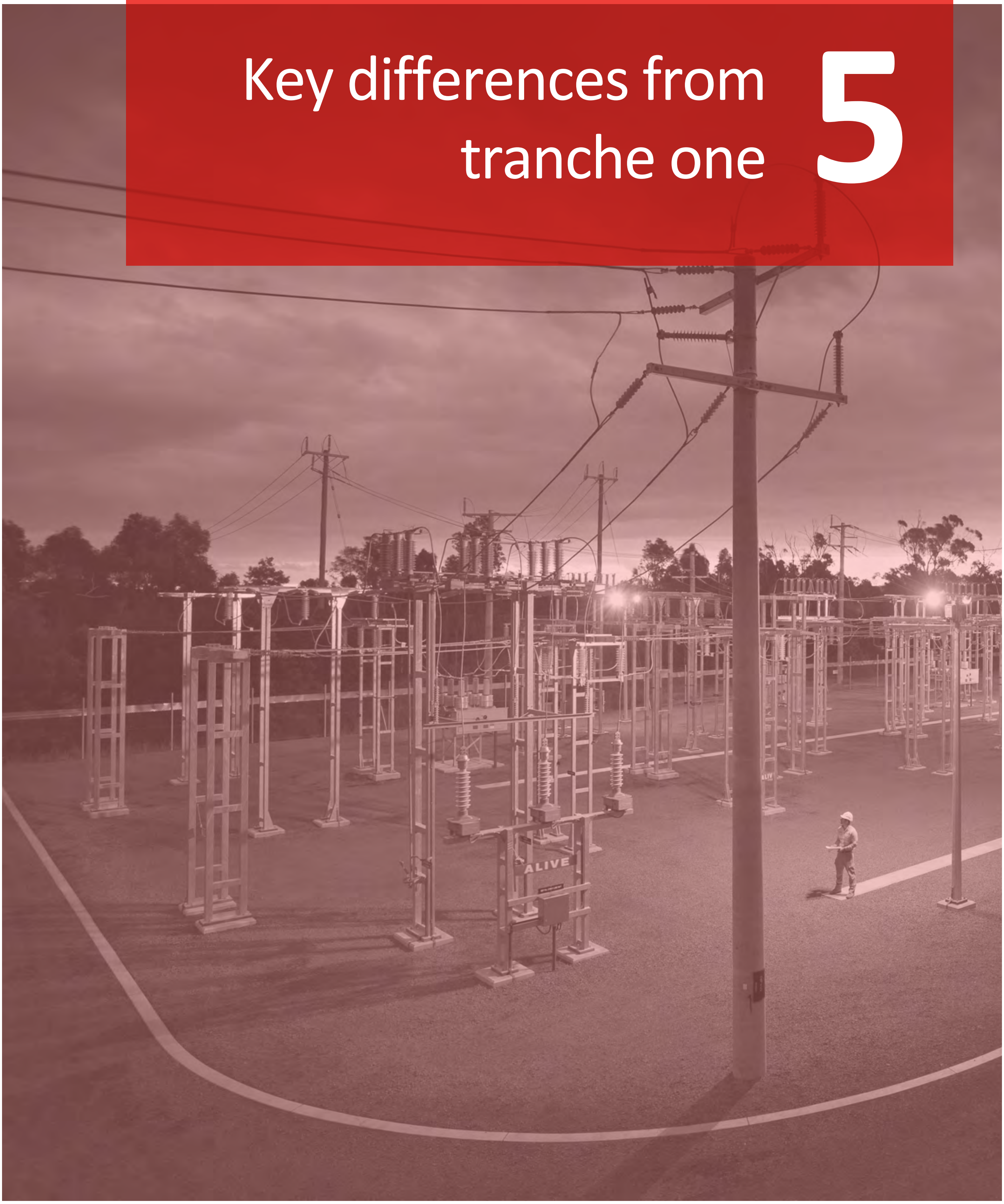

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There are several key differences between our first contingent project application and our second application. The primary point of difference is that this application covers different geographical areas of our network, with consequential changes to the infrastructure and network characteristics and requirements.

Some processes and costs have also changed since our first application. The key changes relate to:

- balancing methodology
- underground cable replacements
- earth grids and current transformer replacements
- GFN installed on a rural long feeder
- GFN enclosures
- testing trailer, and
- spare parts.

We discuss changes to the engagement and solutions for affected HV customers in the next chapter.

5.1 Network characteristics

Our tranche two application relates to the installation of REFCLs in six zone substations in our network, including the large regional towns of Ballarat, Bendigo and Geelong. Four of the six zone substations in this application serve over 25,000 customers, whereas the largest zone substation in our first tranche, Colac, served just 16,500. There are nearly two and half times more customers in tranche two compared with tranche one.

The Ballarat North (**BAN**) and Ballarat South (**BAS**) zone substations serve around 70,000 customers in the greater Ballarat area. The 21 HV feeders emanating from these zone substations cover nearly 3,000 kilometres. The network capacitance is 292 Amps for BAN and 280 for BAS, requiring three REFCLs to be installed in each zone substation. A REFCL will also be installed on a feeder from BAN, given the length and characteristics of the feeder.

Similarly, the Bendigo (**BGO**) zone substation and our 22kV feeders exiting AusNet Services' Bendigo Terminal Station (**BETS**) serve over 40,000 customers in and around Bendigo. The 15 HV feeders cover around 1,250 kilometres. Two REFCLs are required to be installed in each station.

The Geelong (**GL**) zone substation supplies part of Geelong and extends into the surrounding north and western rural towns of Bannockburn, Lethbridge and Meredith. The nine feeders cover nearly 600 kilometres and serve over 25,000 customers. Two REFCLs are required at GL.

The Charlton (**CTN**) zone substation serves Charlton and the surrounding areas. It has six feeders which cover almost 1,200 kilometres, serving nearly 9,000 customers. Given that the network is predominately overhead, only one REFCL is required at CTN.

5.2 Balancing methodology

We have amended our approach to rebalancing of the network based on our experience at Woodend and Gisborne.

Resonant HV distribution networks—such as those used to operate a REFCL—are acutely sensitive to capacitive imbalances.[19] Imbalanced phase-to-ground currents, for example, lead to increased neutral voltage levels.[20] As 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.[21]

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.[22] For our 22kV polyphase distribution network, this requires a fault resistance of 25,400 ohms
- 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).

Each feeder on our network is segmented into isolatable sections, which are determined by the existence of remote controlled devices. A balancing unit is included in each segment, which may be at an Automatic Circuit Recloser (**ACR**) or a gas switch.

In tranche two, we propose the following approach to rebalancing in our design scopes:

- 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 an additional three-phase admittance balancing unit for each feeder to cater for the dynamic nature of network operations
- install fuse savers for any fused sections with overhead line length greater than 9km or 225m of underground cable or the equivalent combination of both overhead line and underground cable
- where a fusesaver is unable to be deployed due to high fault levels, an ACR will be installed to clear each fault as a three-phase section to prevent the feeder continually tripping during days of high sensitivity
- upgrade HV regulators to closed delta configurations with parallel control.

Our revised approach reflects our experience at WND and GSB as well as our tranche one works thus far, and is considered to be the optimal approach to achieve the operational sensitivity set out in the Amended Bushfire

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19 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.

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

21 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.

22 High impedance faults are defined in the Amended Bushfire Mitigation Regulations.

Mitigation Regulations. In particular, to maintain a well-balanced network we need the network balancing assets to be adjustable and to allow for the operation of equipment such as ACRs and fuses.

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

Single phase balancing units and rephasing of the line deliver fixed levels of capacitance. The switching sections are therefore balanced for the static configuration of the network and do not allow for rebalancing of the feeder following a fault using both manual switches and remote control devices. The additional three phase balancing units therefore ensure that required capacity can be maintained on Total Fire Ban days and the maximum number of customers kept on supply during faults.

We have also increased the number of fuse savers on the network. Where a multi-phase fault occurs on a line resulting in either one or two fuses operating, then the main line becomes unbalanced as the remaining energised phases are not providing an evenly distributed capacitance. By installing fuse savers on all phases of a spur, including single phase spurs with a single phase balancing unit, then the main line remains balanced even if the fuse savers operate and the load from the spur is dropped. Fuse savers are installed only on spurs where the imbalance would be large enough to cause the REFCL to incorrectly operate. The number of fuse savers reflects not just overhead cable, but also underground cable. Where a fuse saver is unable to be deployed due to high fault levels, an ACR will be installed to clear each fault as a three-phase section to prevent the feeder continually tripping during days of high sensitivity.

5.3 Underground cables replacement

Based on our experience at Woodend during commissioning, we intend to proactively replace all XLPE cable located in our tranche two zone substation areas that was installed prior to 1989.

At our Woodend zone substation, three feeder exit cables failed following the hardening and commissioning tests and two of these suffered further failures following repair and return to service.

Based on a review of the cable failures, the cause was linked to the presence of 'water trees' within the cable. The cable failed prematurely due to water tree growth as a result of transient and sustained over voltages applied through the operation of the REFCL.

Our experience at Woodend is consistent with the findings in the report prepared by Dr Tony Marxsen for ESV to examine the factors that may create potential safety risks when HV customer sites are supplied by REFCLs. The report identified the high risk of cable asset failures in its assessment of factors that may create potential safety risks when high voltage (**HV**) customer sites are supplied by REFCL protected networks.

The report reviewed cable assets at twelve customer sites. Based on the review, the report listed the age profile of the XLPE cable and the associated level of cable failure risk. It identified that XLPE cable installed before 1980 had a high risk of failure and the default action should be to replace the cable. Furthermore, it identified that cables manufactured between 1980 and 2000 should be tested and those that fail should be replaced.

Figure 5.1 Marxsen report estimated failure risk of customer XLPE cable assets and appropriate mitigation action

Number of cables	Total length	Manufacture	Risk	Default action
34	5.3 kilometres	Post 2000	Low	Nil
46	6.7 kilometres	1990s	Low[18]	Test
24	7.0 kilometres	1987	Medium	Test
2	30 metres	Pre-1980	High	Replace

Source: Marxsen Consulting Pty Ltd, Customer Assets Directly Connected to REFCL networks: a preliminary risk survey, 20 June 2017, p. 16.

The report referred to studies in Europe and North America.[23] It stated that the customer owned XLPE cable in Victoria's REFCL protected networks should suffer one failure every 4.2 years. North American data would suggest one failure every six months. The report then noted that given the cables reviewed in the report had all been in service for a long period in non-REFCL networks, the North American figures may be more relevant. That is, high failure rates should be expected.

We intend to replace all first generation XLPE cables given the high risk of failure. The risk of failure arises from:

- manufacturing defects and contamination leading to the presence of and growth of water trees
- premature failures due to water tree growth as a result of transient and sustained overvoltages
- existing elevated risk of failure (relative to later types of XLPE cables) due to overvoltage applied during REFCL operation.

Our tranche two sites contain a greater amount of XLPE cable compared with tranche one.

Further details regarding XLPE cable failures are provided in attachment REFCL2.10.

5.4 Earth grids and current transformer replacements

Based on our experience at Woodend zone substation, we need to undertake additional works to ensure that we can achieve required capacity required under the Amended Bushfire Mitigation Regulations. These works encompass:

- construction of additional earth grid components
- replacement of current transformers.

These are discussed in turn below.

Earth grids

At our Woodend zone substation, we installed two REFCLs that can operate on electrically separated networks, each providing more sensitivity than if the two were combined. In this separated state, it was observed that a voltage on one of the REFCLs would in turn induce a smaller voltage on the other REFCL. This means that when one REFCL is handling a fault, the second REFCL measures a quantity that appears as an earth fault. The magnitude was in excess of the trigger level for a high impedance fault on the healthy system.

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23 REFCL2.12 Marxsen Consulting Pty Ltd, *Customer Assets Directly Connected to REFCL networks: a preliminary risk survey*, 20 June 2017, p. 16.

The cause of the second fault at Woodend was an induced neutral voltage as a result of earth grid impedances. Earth fault detection in REFCL networks is performed through measurements at a zone substation, specifically measurement of neutral voltage. This neutral voltage, measured across the Arc Suppression Coil, develops as a result of a phase to ground fault – and relates to the impedance of the fault.

Our proposed solution is to perform earth grid works to reduce the earth grid impedance to low levels at zone substations with more than one REFCL, ensuring that any induced voltage will be below fault detection levels.

Earth grids generally consist of a grid of copper laid underneath the zone substation, occasionally with deep probes. The earth grid is the point of return for all HV earth faults supplied from the zone substation as well as the reference point for all voltages.

We intend to perform site surveys, soil resistivity testing and to accurately model the earth grid of our multiple REFCL zone substations. We will design and construct additional earth grid components, such as larger grids, additional stakes or deep bored probes as required by the specific site conditions. These sites will likely have varied soil conditions that result in different physical works.

Current transformers

The ability to detect faults and perform diagnostic testing to the level specified in the Amended Bushfire Mitigation Regulations requires very accurate current measurements.

In balancing the network using current transformers (**CT**) at Woodend, we required low error in terms of amplitude and angle of measured current. In addition to the challenge of balancing, when attempting to confirm the presence of a 25,400 Ohm fault during diagnostic testing we require this same high level of performance. During testing it was identified that the residual current measured from these balanced feeders was inconsistent with the noise often exceeding the threshold for detection by orders of magnitude.

Despite using the existing protection CTs, metering class CTs as well as highly accurate 'core balance' CTs, we did not obtain the required performance. We are currently installing further CTs at Woodend to continue to strive for the specifications mandated in the regulation.

We intend to replace all CTs in tranche two zone substations that do not have the required accuracy. We will install outdoor 'post type' CT structures to stand adjacent to circuit breakers. While the replacement CTs are cheaper than replacement of the circuit breakers housing CTs, the replacement CTs require additional civil and structural works to modify the 22kV bus work to maintain safe clearances between high voltage assets and other structures.

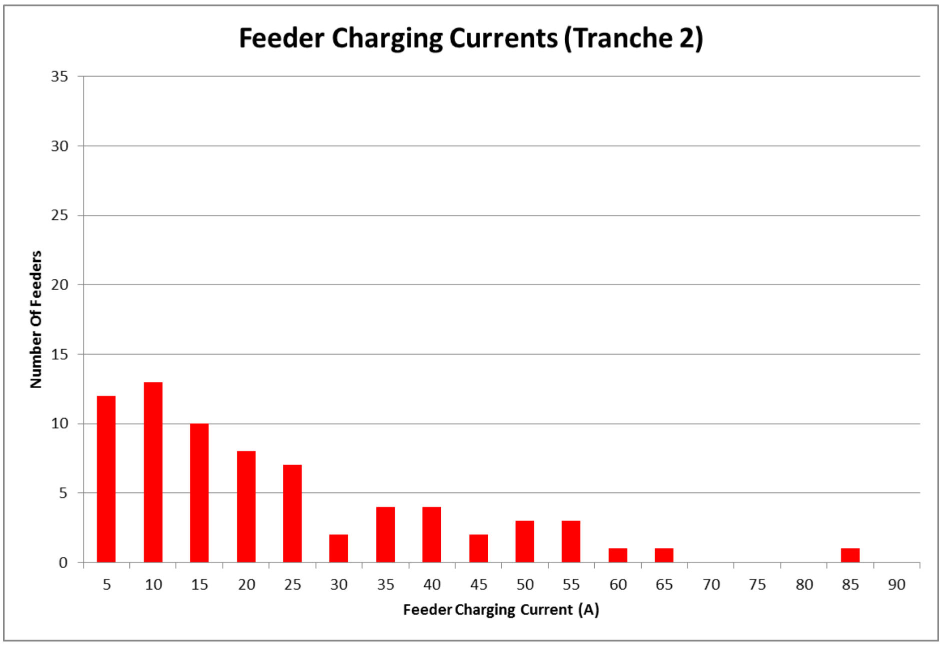
5.5 GFN on a feeder

The BAN011 feeder is 411km long, with five percent underground, and our assessment is that the REFCL at BAN zone substation would not be sensitive enough for a phase-to-earth fault at the end of the feeder to trigger the REFCL to operate. Consequently, we need to install a REFCL and isolating transformer along the rural long feeder to ensure that the REFCL operates as required.

Network size plays a significant role in the ability for a REFCL to effectively detect and confirm high impedance faults. Whilst described in terms of capacitive charging current, the parameter that affects REFCL sensitivity and performance is damping. Damping is the resistive leakage current of the network, and is often represented as a percentage of the capacitive current.

The average magnitude of feeder charging current in our REFCL program is approximately 22 amps; this is depicted diagrammatically in the following histogram, of expected feeder charging currents in tranche two.

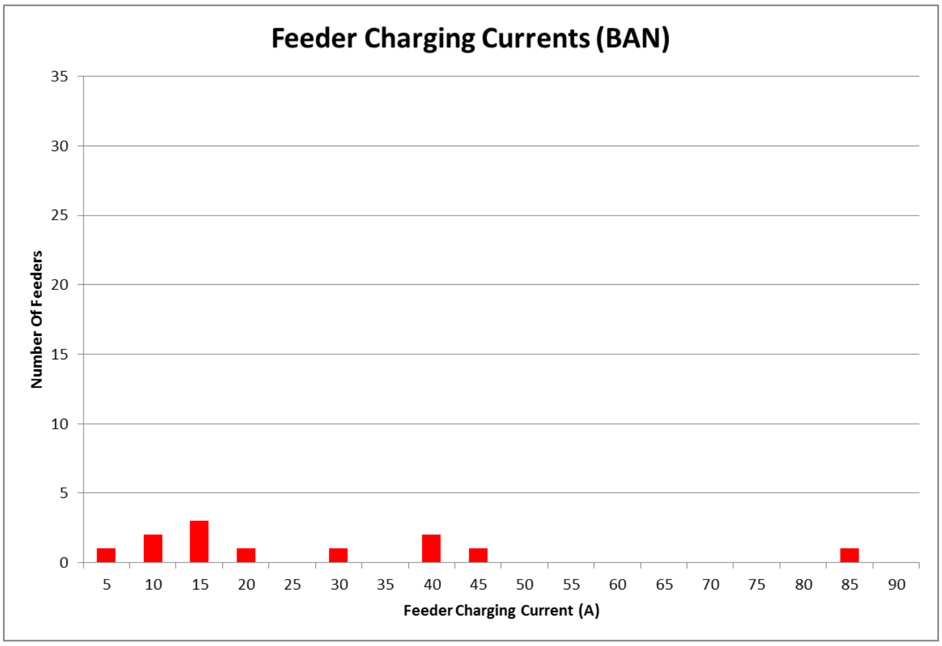
Figure 5.2 Feeder charging currents for all feeders in tranche two



Source: Powercor

Our BAN011 feeder is made up of 390km of overhead line and 21km of underground cable, with an estimated charging current of 84 amps. This is twice the next largest feeder at BAN, as shown in the figure below. It is also larger than the aggregate charging current at some zone substations (such as Camperdown).

Figure 5.3 Feeder charging currents for all feeders from BAN zone substation



Source: Powercor

In order to assure REFCL performance, some segmentation is required of this network. This will be achieved by installing a GFN and an isolating transformer along the BAN011 feeder.

5.6 GFN enclosures

The vendor for the supply of GFN enclosures in tranche one, Ennesty, went into liquidation in mid 2017.

We have sourced GFN enclosures for tranche two from a different supplier, however there is an increase in the unit cost compared with tranche one.

5.7 Testing trailer

We have included costs for a new testing trailer in this application. A second testing trailer is required as the testing trailer purchased for tranche one will still be in use for commissioning activities for tranche one. Two testing trailers will also be necessary on an ongoing basis to enable testing and commissioning of different zone substations at the same time, as well as for annual testing of the REFCLs.

5.8 Spare GFN

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

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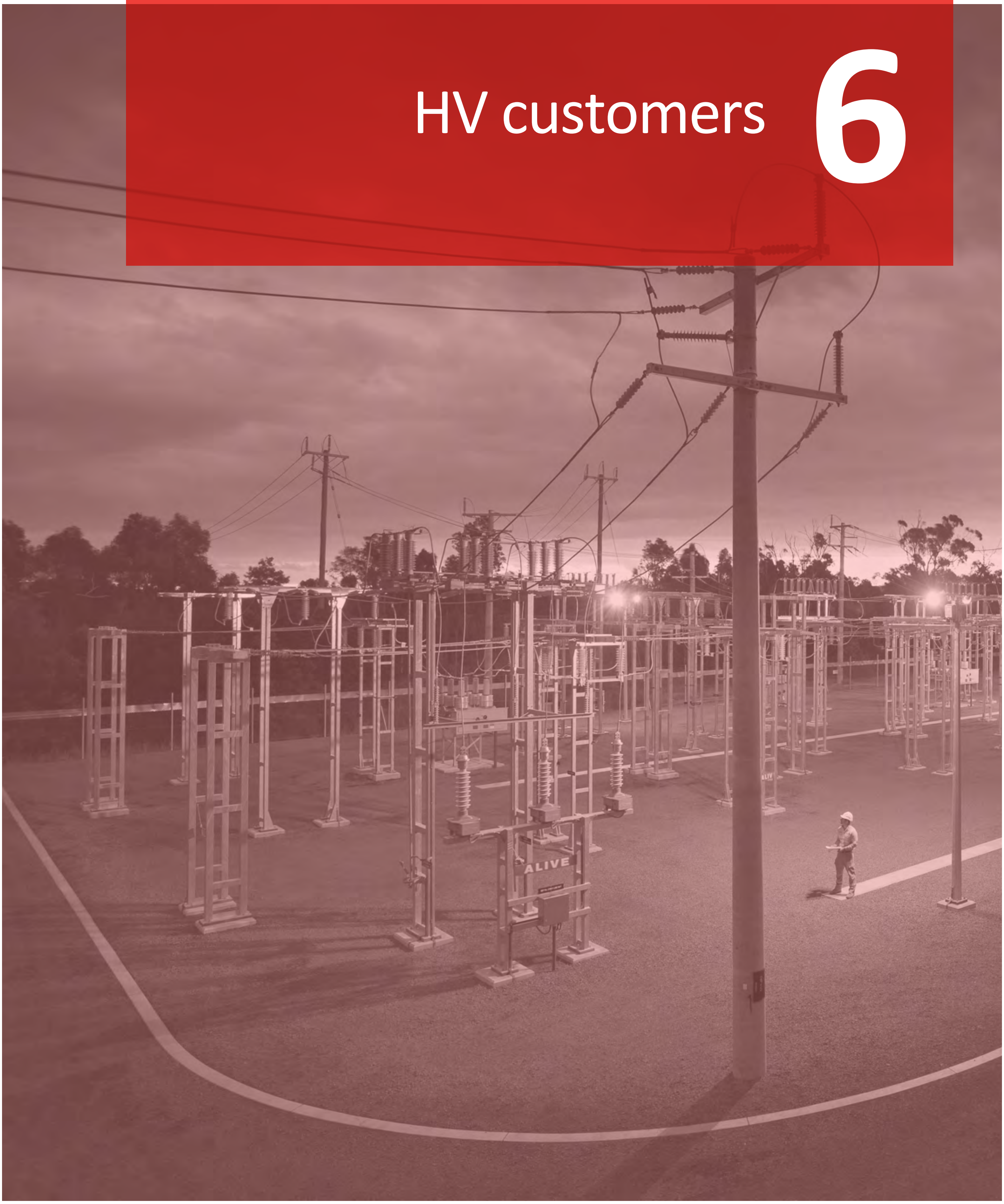
HV customers 6



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We have actively engaged with our HV customers to assist them in understanding the implications of the Amended Bushfire Mitigation Regulations on their electricity installation. We are continuing to work with them to assist in identifying the most efficient solution to enable their HV connection to operate safely alongside the operation of our REFCL.

At the time of preparing this application, we remain liable under the Distribution Code for adverse effects to HV customers as a consequence of REFCL operation.

6.1 Regulatory context

The AER accepted in its tranche one decision that Victorian distributors are liable under the Distribution Code for adverse effects to HV customers as a consequence of REFCL operation.[24]

As the AER is aware, the Essential Services Commission (**ESCV**) has commenced a review of the Distribution Code. The review will focus on clause 4.2.2 which sets the allowable variations from nominal voltage levels that distributors must maintain throughout the network, as well as inter-related clauses. The ESCV recognises that voltage magnitude and time duration dimensions of this clause must be amended to allow for the operation of the REFCL. The ESCV review of voltage standards to support the introduction of REFCLs is due to be completed in August 2018.[25] The review is not expected to amend the Distribution Code on a retrospective basis.

Should the effect of the ESCV review be that distributors are no longer liable for impacts on HV customers from the higher voltages caused by the operation of the REFCL, then we expect that the AER will accept any costs that we incurred to comply with the Distribution Code up until the time that it changed.

6.2 Approach to HV customers

We visited 29 initial customer sites across 22 customers in tranche two, and prepared initial scopes of the connections. Through discussions with the various owners, it was agreed that two sites could be abolished and two could be supplied via another connection to the site. There are 25 customer sites across 20 customers now included in tranche two.

These initial scopes did not identify whether or not the customer equipment, beyond our point of supply, was able to withstand the higher voltages that occur when the REFCL is in operation. Therefore, we engaged an independent consultant to review each connection and to discuss potential options with the HV customer.

The options that the consultant discussed with the HV customers included:

- transferring the connection from HV supply to LV supply
- hardening the HV customer assets to withstand the higher voltages (which would involve the HV customer and Powercor entering into a written agreement to vary the voltage obligations under the Distribution Code)
- installing an isolating transformer between our network and the HV customer network to stop the higher REFCL voltages impacting their network .

Each option has different positive and negative consequences which the consultant discussed with the HV customer. The consultant identified the solution that best meets the needs of the HV customer.

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24 AER, *Final Decision Powercor Australia Contingent Project Installation of Rapid Earth Fault Current Limiters (REFCLs) – tranche 1*, August 2017, p. 6.

25 https://www.esc.vic.gov.au/project/energy/56870-review-of-voltage-standards/

The independent consultant identified where the costs of hardening the HV customer sites were likely to be less than the cost of installing isolating substations. At the stage of preparing this application, hardening was identified as the most cost efficient option for two HV customer sites. Within this application we have included costs for payments to those HV customers to vary the voltage obligations in the Distribution Code, for the purposes of allowing the customers to harden their assets.

For the remaining HV customers, we have included costs to install isolating substations for each site. Where possible, efficiencies have been identified in the deployment of isolating substations such that two customers in close proximity will share an isolating substation.

A scope of work for each HV customer is provided in confidential attachment REFCL2.09.

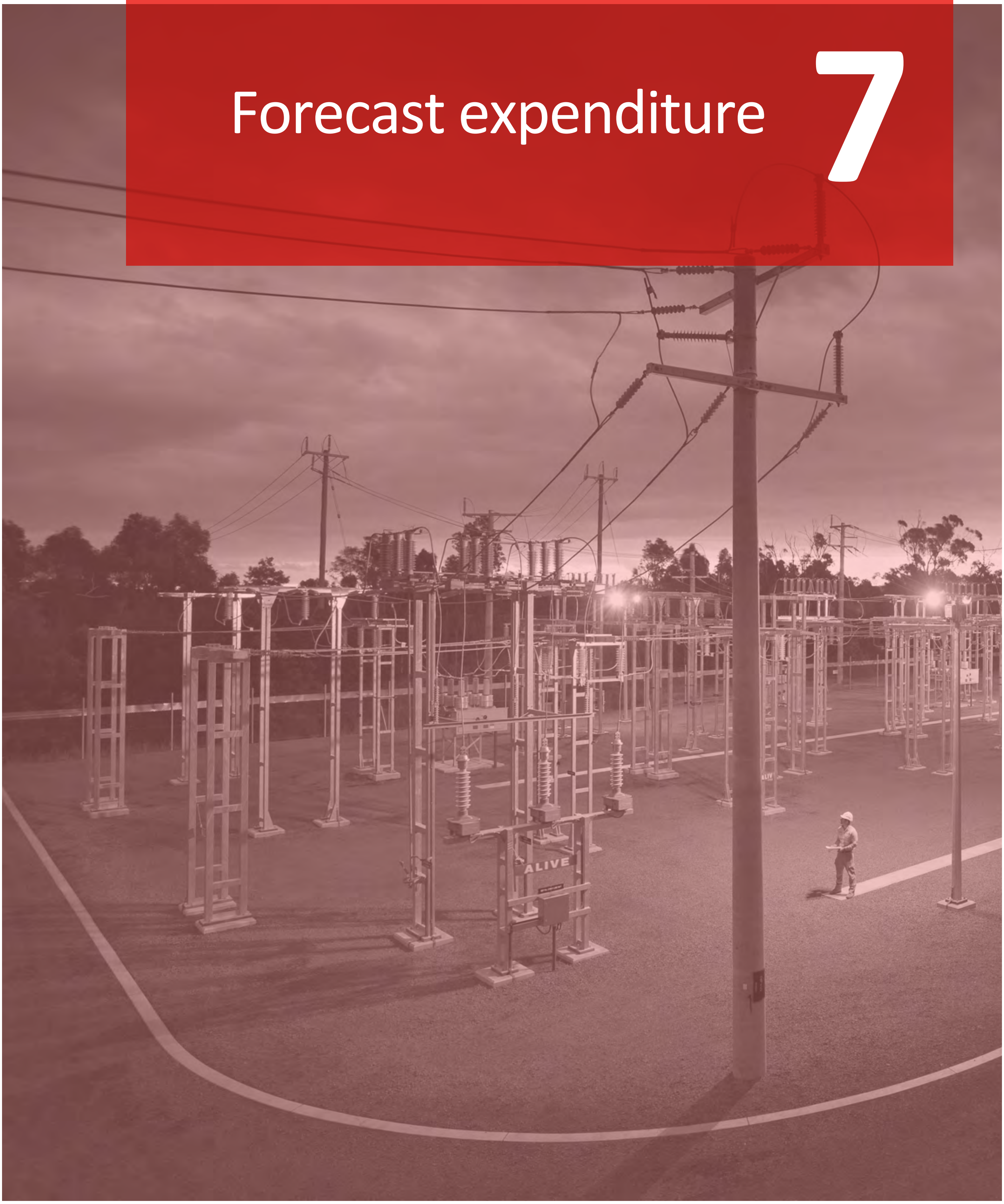
6.3 High voltage customer assistance program

The AER may be aware that the Victorian Government is proposing a high voltage customer assistance program (**HCAP**) to support the assessment of HV customer installation and potentially to fund any works to enable those installations to be REFCL compatible.

The Victorian Government has indicated that the total size of the fund is $10 million, across all distributors and tranches. At the time of preparing this application, however, details regarding the timing and eligibility requirements for the fund were yet to be released. It is also unclear if the HCAP is dependent upon a change in the Distribution Code to place the onus on HV customers to ensure that their connection is REFCL compatible.

In the event that a HV customer in tranche two is granted funding under the HCAP scheme prior to the AER making its decision on this application, then we will advise the AER.

Forecast expenditure 7



April 2018

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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 is set out in table 7.1.

Table 7.1 Site specific drivers of expenditure

Expenditure driver	BAN	BAS	BETS	BGO	CTN	GL
Customer numbers Higher customer numbers add complexity to balancing requirements, control room operations and commissioning costs	32,625	37,059	25,988	14,581	7,853	25,255
Surge arrestor sites The number of surge arrestor sites are a key labour driver (noting three phase replacements require more labour than single phase) and also impact traffic management	2,183	1,906	1,239	758	694	1,206
ACR volumes ACR models that are not compatible with the operation of a REFCL network need to be replaced	24	20	9	6	15	9
Network capacitance (A) Network capacitance is a driver of the number of GFNs required to be installed at each zone substation	292	280	148	125	93	149
Total route length (km) Total route length impacts capacitive balancing requirements	1,420	1,365	742	514	1184	602
Remote-controlled switching sections Three phase balancing requirements are primarily driven by the sections of our network bounded by remote-controlled switching devices	53	44	20	13	32	26
Number of feeders Commissioning costs are impacted by the number of feeders	12	9	8	7	6	9
Number of HV customer sites A solution is required for each HV customer site to ensure it is compatible with the operation of a REFCL	9	5	4	2	4	1

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 REFCL2_MOD.01).

7.1 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.

7.1.1 Ground Fault Neutralizer

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
  - 250 volts within 2 seconds
- during diagnostic tests for high impedance faults, to limit:
  - fault current to 0.5 amps or less
  - 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 108A. This range has been developed with input from the REFCL technical working group (**TWG**), and based on our experience at the Woodend, Gisborne and Camperdown zone substations. It is discussed in detail in the attached technical document—implementation and optimisation of REFCL systems.

As shown in table 7.2, the total system capacitance exceeds 108A at all zone substations except CTN. The total system capacitance is between 108A and 216A at BETS, BGO and GL and accordingly, these sites require two GFN units. Three GFN units will be required at BAS as the total system capacitance is between 216A and 324A. This is consistent with the analysis set out by Marxsen Consulting in their report for DEDJTR. Specifically, Marxsen

[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.

Consulting stated that to achieve performance standards, some substations supplying larger networks may have to be fitted with multiple REFCLs.[27]

Table 7.2 GFN requirements relative to line/cable length

Network characteristic	BAN	BAS	BETS	BGO	CTN	GL
Total system capacitance (A)	292	280	148	125	93	149
Underground cable (km)	74	71	37	34	5	41
Overhead line (km)	1,346	1,294	706	480	1,179	561
GFNs required	**3***	**3**	**2**	**2**	**1**	**2**

Source: Powercor
* Note: 3 GFNs are required for the zone substation. An additional GFN will be included on a long feeder.

Four GFNs are required for the BAN zone substation and associated feeder network. Three of those GFNs will be located within the zone substation, while one GFN will be on a rural long feeder. This is further discussed in section 5.5.

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).

GFNs can currently only be sourced from a single supplier, although we are exploring other market opportunities. Our unit costs reflect the latest quotes from our supplier.

7.1.2 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 relay and protection equipment at the zone substation, and SCADA and communications infrastructure.

Our costs for service station transformers, AC changeover boards and GFN enclosures (discussed in section 5.6) are based on recent quotes that we have received from suppliers. An extra panel is required for our indoor switchboard units, resulting in a slight increase in cost compared with tranche one. All other primary plant unit costs are unchanged from tranche one, where applicable.

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. These requirements are set out in our expenditure build-up model, and are further discussed in the functional design scopes for each site.[28]

GL zone substation

The installation of the two REFCLs is complicated at GL due to the existing physical constraints at the site. That is, there is insufficient space to install multiple GFNs and corresponding switching capability.

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

28 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.

As set out in attachment REFCL2.07, we considered several design options to ensure the least-cost technically acceptable solution was determined. The recommended option is to install an indoor switch room and relocate one of the outdoor 22kV busbars to the indoor switchboard to provide sufficient space for the REFCL equipment. This will result in reconfiguration of the 22kV and 66kV switchyard.

To achieve this, we will offload five feeders and a transformer via temporary arrangements. This will involve staging inclusive of temporary primary construction, temporary secondary and protection/control construction and commissioning. These temporary arrangements will require remote end works for back bone feeders e.g. open points and protection and control schemes.

BETS zone substation

The works at BETS zone substation require works to be undertaken by AusNet Services Transmission on our behalf. This co-ordination adds greater complexity to the project.

7.2 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
- HV cable replacements.

We have also included costs associated with HV customers for the purposes of maintaining compliance with the Distribution Code.

7.2.1 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.

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 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).

Consistent with tranche one, and as set out in GHD's final report, we 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)
- type W: ABB polim D polymeric zinc oxide, class A 22kV.

To identify these surge arrestors on feeders served by our tranche two 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 some GL feeders) is shown in table 7.3.

Table 7.3 Surge arrestor sites

Surge arrestors	BAN	BAS	BETS	BGO	CTN	GL
Surge arrestor sites (existing)	3706	3209	1814	1294	1023	1835
Surge arrestor sites (replacements)	2183	1906	1239	758	694	1206

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.

Our unit costs for surge arrestor replacements are unchanged from tranche one.

7.2.2 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.

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:[29]

> *… 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 7.4. Our gas switch control box upgrade volumes are shown in table 7.5.

Table 7.4 ACR replacements and control box upgrades

Volumes	BAN	BAS	BETS	BGO	CTN	GL
Existing ACRs	24	20	9	6	15	9
RVE and VWVE ACRs (replacement volume)	9	7	1	3	4	2
ACR control box replacements	8	8	6	2	7	4

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

Table 7.5 Gas switch upgrades

Volumes	BAN	BAS	BETS	BGO	CTN	GL
Existing remote controlled gas switches	17	15	3	0	11	8
Gas switch control box upgrades	13	2	3	0	0	0

Source: Powercor

Our unit costs for ACR replacements are unchanged from tranche one.

7.2.3 Capacitive balancing

As discussed in section 5.2, we have amended our approach to rebalancing of the network based on our experience at Woodend and Gisborne zone substations. In particular, we will install:

- a greater proportion of three phase admittance balancing units
- additional fuse savers in the network.

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.

<u>Single phase balancing units and re-phasing</u>

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 experience at Gisborne and Woodend zone substations for balancing units, and reflects a less conservative approach for re-phasing (i.e. at Gisborne and Woodend, we initially performed re-phasing works every 5.6km).

<u>Three phase balancing units</u>

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 4,000 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. We also propose to install an additional three-phase admittance balancing unit for each feeder to cater for the dynamic nature of network operations.

A summary of our admittance balancing unit and re-phasing requirements is set out in table 7.6.

Table 7.6 Admittance balancing units and re-phasing requirements

Volumes	BAN	BAS	BETS	BGO	CTN	GL
Isolatable sections (existing)	993	1113	525	337	532	578
Remote-controlled switching sections (existing)	53	44	20	13	32	26
Re-phasing sites	43	45	15	16	21	16
Admittance balancing units (single phase)	32	31	10	11	13	20
Admittance balancing units (three phase)	77	61	35	27	44	43

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.[30]

Our unit costs for admittance balancing units and re-phasing works are unchanged from tranche one.

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).[31]

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).

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 or 225m of underground cable or the equivalent combination of both overhead line and underground cable.

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 7.7. The basis for these parameters is set out in detail in attachment REFCL2.11—the implementation and optimisation of REFCL systems.

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

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

Table 7.7 System requirement parameters

Parameter	Value	Comments
Network capacitance	95A	Mid-point of range of maximum network capacitance per GFN
Damping resistance	3.0–4.0%	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: REFCL2.11 Powercor, *Implementation and optimisation of REFCL systems*, March 2018.

Where a fusesaver is unable to be deployed due to high fault levels, an ACR will be installed to clear each fault as a three-phase section to prevent the feeder continually tripping during days of high sensitivity.

Our unit costs for fuse savers are unchanged from tranche one.

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.[32]

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.[33]

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

Our unit costs for HV regulators upgrades in close-delta configuration are unchanged from tranche one. However our unit costs are slightly higher for the control box, based on recent quotes that we have received from suppliers.

7.2.4 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, this assessment was to ensure these assets could withstand elevated voltages up to 24kV for a period of

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

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

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.

Table 7.8 FG switchgear replacements

Volumes	BAN	BAS	BETS	BGO	CTN	GL
Replacement of switchgear	9	6	5	6	0	2

Source: Powercor

Our unit costs for distribution switchgear replacements are unchanged from tranche one.

7.2.5 Cable replacement and reterminations

HV cable is installed throughout our network in a range of different specifications. We propose to undertake a proactive replacement approach for XLPE cable, and a reactive replacement approach for underground HV cable that fails. We also propose to reterminate some cables to evenly distribute capacitance at particular zone substations.

HV cable replacement

As discussed in section 5.3, we intend to proactively replace all XLPE cable that was installed prior to 1989.

Our forecast for underground HV cable replacements reflects replacement of all XLPE installed prior to 1989, testing of the remaining cable (including XLPE post 1989), as well as replacement of a percentage of the remaining cable. The percentage failure rate reflects the percentage of other underground HV cable that actually failed. The forecast cost is based on our actual repair costs (on a per meter basis).

Feeder exit relocation

Our planning assumption is that a single GFN can support the required performance standards to a maximum total system capacitance of approximately 108A. However, the feeder sizes are not evenly spread at the BAS and BAN zone substations, such that a single GFN may need to support feeders with a charging current of greater than 108A.

To remedy this, we propose to balance out the capacitance between our REFCLs at BAN and BAS. This will be achieved by reterminating cables from one location to another to ensure that each GFN is not supporting feeders with a charging current in excess of 108A.

7.2.6 HV customers (isolation substations)

The Distribution Code requires we maintain a prescribed nominal voltage level at the point of supply to customers' electricity installations.[34] The Distribution Code also permits variations to these limits, with the extent of these variations decreasing as the time period increases.[35]

[34] Electricity Distribution Code, cl. 4.2.1.

The testing and operation of REFCLs on our network will lead to breaches of the Distribution Code—for example, although it 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 Distribution Code
- when a REFCL is in operation, phase-to-ground over-voltages up to 190 per cent may arise.

As discussed in chapter 6, the ESCV has commenced its review of the Distribution Code. At the time of preparing this application, we remain liable under the Distribution Code for adverse effects to HV customers as a consequence of REFCL operation.

To maintain compliance with the existing Distribution Code, we propose to install isolation substations at the point of supply to many of our customers connected directly to our HV network. In this tranche, this solution applies to 23 sites.

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 7.9. The expenditure included for isolation substations in our expenditure build-up model reflects the total installation cost.

Table 7.9 Isolation substation requirements

Volumes	BAN	BAS	BETS	BGO	CTN	GL
3 MVA substations	3	3	2	0	4	1
6 MVA substations	6	1	2	2	0	0
Total isolation substations	**9**	**4**	**4**	**2**	**4**	**1**

Source: Powercor

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. In this case, the installation of isolating substation is the most cost efficient solution.

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 Distribution Code (and as such, deemed distribution contracts do not provide relief for us on this matter).

The isolating substation that we have procured contains the isolating transformer within a kiosk together with switchgear, current transformers, voltage transformers, supply transformers, batteries as well as the required protection and control capabilities. The updated unit costs in this application, based on the AER model from tranche one, no longer include an ACR and associated labour, however it includes increased costs for the isolation substation to reflect actual market-based quotes for tranche one sites.

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[35] Electricity Distribution Code, cl. 4.2.2.

HV customer site variable costs

In addition to the installation of an isolating substation, for each site we have separately identified the costs for installation of a HV switch on the distribution pole, civil costs for trenching from the pole to the isolation transformer and the costs to install a ring main unit (**RMU**).

Where possible, we have identified efficiencies in the deployment of isolating substations at customer sites. As two customer sites are located within close proximity to each other, we have proposed for the customers to share an isolating substation thereby reducing the overall cost of the HV customer solution.

7.2.7 HV customers (hardening solution)

We have included costs for payments to HV customers in exchange for their agreement to a change in our obligations under the Distribution Code. In this tranche, this solution applies to two customers connected at two sites.

As the AER is aware, the Distribution Code requires a distributor to maintain a prescribed nominal voltage level at the point of supply to the customer's electricity installation. Variations from those voltage levels are permitted within specified limits and durations.

The installation of isolating substation may not be the most cost efficient solution. In these cases, we propose to negotiate with the HV customers and, if they agree, pay them so that we can deliver voltages outside of the limits specified in the Distribution Code.

The Distribution Code enables a distributor or a customer to, by written agreement, expressly vary their respective rights and obligations. As we would be reducing the customer's right to have the existing voltages specified in Distribution Code apply at the point of supply to the customer's electrical installation, we must give a benefit of equal value in return for the customer's agreement for us to deliver voltages outside those levels.

As a result, we will make payment to HV customers comprising:

- the costs for the customer to harden their equipment to withstand the higher voltages from the REFCL
- the costs of having the equipment hardening independently verified
- potentially an amount for inconvenience as a benefit of equal value to the right to have the voltage requirements apply during testing and operation of the REFCL.

The HV customer costs for a hardening solution are specific to each customer site.

7.3 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.[36] 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.

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

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 7.8.1).

7.4 Materials cost forecast

As discussed in sections 7.1 and 7.2, 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 and tranche one sites. 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). Furthermore, we are currently exploring other market opportunities for a second supplier.

The forecast prices for our remaining plant reflect our previous experience purchasing and installing this equipment in the course of our normal operations, or where applicable, based on the latest quotes from suppliers for tranche one sites.

7.5 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 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.

7.5.1 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. Ballarat resource partner rates are used for BAS, BAN and GL, and Bendigo rates for BETS, BGO and CTN). 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.

7.5.2 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

Commissioning works are required to finalise balancing of the 22kV distribution network, to assess the network compatibility with healthy phase over-voltages, to test and prove all protection schemes associated with the REFCL and to identify the sensitivity capability of the REFCL.

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 to confirm if the network is appropriately hardened or identify weak or vulnerable equipment
- primary fault testing—this testing uses a portable earth fault test truck to test 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).[37]

Stress testing of the network involves utilising the Residual Current Compensation (**RCC**) inverter to artificially elevate the phase-to-earth voltage on each feeder to place the same stress on the network assets as would be experienced during normal REFCL operation. This allows for either confirmation that the network is appropriately hardened or for any weakened or vulnerable equipment on the network to fail and create a fault, enabling identification of the location of the asset to be replaced.

Stress testing is undertaken on each phase of each feeder. At WND and GSB, this was undertaken in bypass operating mode, assuming a permanent fault at 1000 Ohm impedance. Each test can take up to 20 minutes per test. The ensures that the network is resilient to the over-voltages that exist during REFCL operation, and reduces the risk of secondary faults on the 'healthy' phases which may increase the risk of a fire start and may be difficult to identify and remediate the fault.

Primary fault testing involves manually creating a fault on the 22kV distribution network using a portable earth fault truck to simulate phase to earth faults. These tests allow for real scenario testing of protection schemes that are installed in the zone substation that are vastly different to existing protection equipment. Traditionally protection schemes are tested 'offline' as the operation of the equipment is well understood. Simulation of signals to the GFN and other corresponding secondary equipment is highly complex and not well understood.

Primary fault testing also allows for compliance testing. These tests identify the level of sensitivity that can be achieved on the network given the achieved balance and network damping, and understand our ability to meet the 25,400 Ohm fault sensitivity specification as well as speed performance.

Primary fault testing must be completed:

- on each phase of each feeder
- in each operating mode of the REFCL
- for transient or permanent faults
- at different levels of impedance (i.e. 400 or 25,400 Ohms).

The three operating modes of the REFCL are shown in the table below. Our BMP requires us to operate the REFCLs in fire risk mode on days of total fire ban (**TFB**) days with the best available sensitivity. Our BMP also

37 See Powercor, *Bushfire Mitigation Plan*, Revision 4.1b, 29 March 2017, p. 21.

states our intention to trial the operation of the REFCLs on certain days, which are also shown in the table below. We may not always employ an operating mode in accordance with our stated intention. [38]

Table 7.10 REFCL operating modes

Operating mode	Operational process	Trial operation
Fire risk mode	• When a fault is detected the REFCL compensates immediately • Waits a set time 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	On TFB days and during the fire season (i.e. for the six month period between October and March).
Normal mode	• When a fault is detected the REFCL compensates immediately • Waits a set time 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	For low fire risk days
Bypass mode	• When a fault is detected the REFCL compensates immediately • Waits a set time 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)	On non-TFB days when fire risk mode and normal mode are not deployed

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.

The commissioning tests set out above 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 7.7, 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:

[38] 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.

- 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)
- 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 tranche one sites, and is consistent with our typical budgeting methodology.

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 two, and allocated these costs to each zone substation based on the percentage of construction costs per site relative to the total for tranche two. This forecast reflects the complexity and challenging timeframes of our REFCL program.

<u>Change management and training requirements</u>

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 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.

Our training program will include all line workers at our Ballarat depot and new line workers at the Bendigo depot. 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).

<u>Network, regulatory and customer communications resources</u>

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—detailed project planning is required to manage the installation of REFCLS 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 for planning, construction, operation and maintenance
- 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 with our existing resource compliment. At GSB and WND alone, the control room job numbers increased by 43 per cent due to the REFCL program
- 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 at least two planned outage notifications per customer, and community awareness measures (such as notifications in local media). The increase in customer numbers in tranche two compared with tranche one means that our customer communication and management costs have increased
- HV customer management—we are in regular contact with all of our HV customers regarding the process to investigate their installation and identify the most efficient solution to enable their HV connection to operate safely alongside the operation of our REFCL.

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.

7.6 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
- line surveys were used to determine surge arrestor replacement volumes
- civil works reflect the requirements set out in our functional design scopes, and accordingly, these forecasts vary by site.

7.7 Forecast expenditure summary

A summary of our expenditure forecast for our tranche two REFCL sites is set out in table 7.11. 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 7.11 Summary of total expenditure requirements ($m, real 2015)

Forecast expenditure	2016	2017	2018	2019	2020	Total
Project costs (capitalised)	-	-	74.8	52.9	-	127.7
Project costs (expensed)	-	-	3.0	2.3	-	5.3
Incremental re-balancing works	-	-	-	-	0.2	0.2
Incremental compliance testing	-	-	-	-	0.2	0.2
Incremental technical support	-	-	-	-	0.0	0.0
Total	**-**	**-**	**77.8**	**55.3**	**0.5**	**133.5**

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

7.8 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 7.7 (and the corresponding depreciation impact, discussed in section 7.8.1).

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

Table 7.12 Summary of incremental revenue requirements ($m, real 2015)

Building block components	2016	2017	2018	2019	2020	Total
Return on capital		0.1	0.1	5.0	8.2	13.3
Return of capital (regulatory depreciation)		0.0	0.0	5.3	6.9	12.2
Operating expenditure		0.0	3.2	2.6	0.6	6.4
Net tax allowance		-0.0	-0.0	0.7	0.7	1.4
Annual revenue requirement (unsmoothed)		0.0	3.3	13.6	16.4	33.3
Annual revenue requirement (smoothed)		**0.0**	**0.0**	**16.4**	**17.2**	**33.6**

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

7.8.1 Accelerated depreciation

As set out in section 7.2.1 and section 7.2.2, 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
- 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.[39]

SWER ACRS, in particular, were replaced based on the recommendations of the VBRC, and subsequent direction from ESV. The AER noted the following:[40]

> *[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.

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

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

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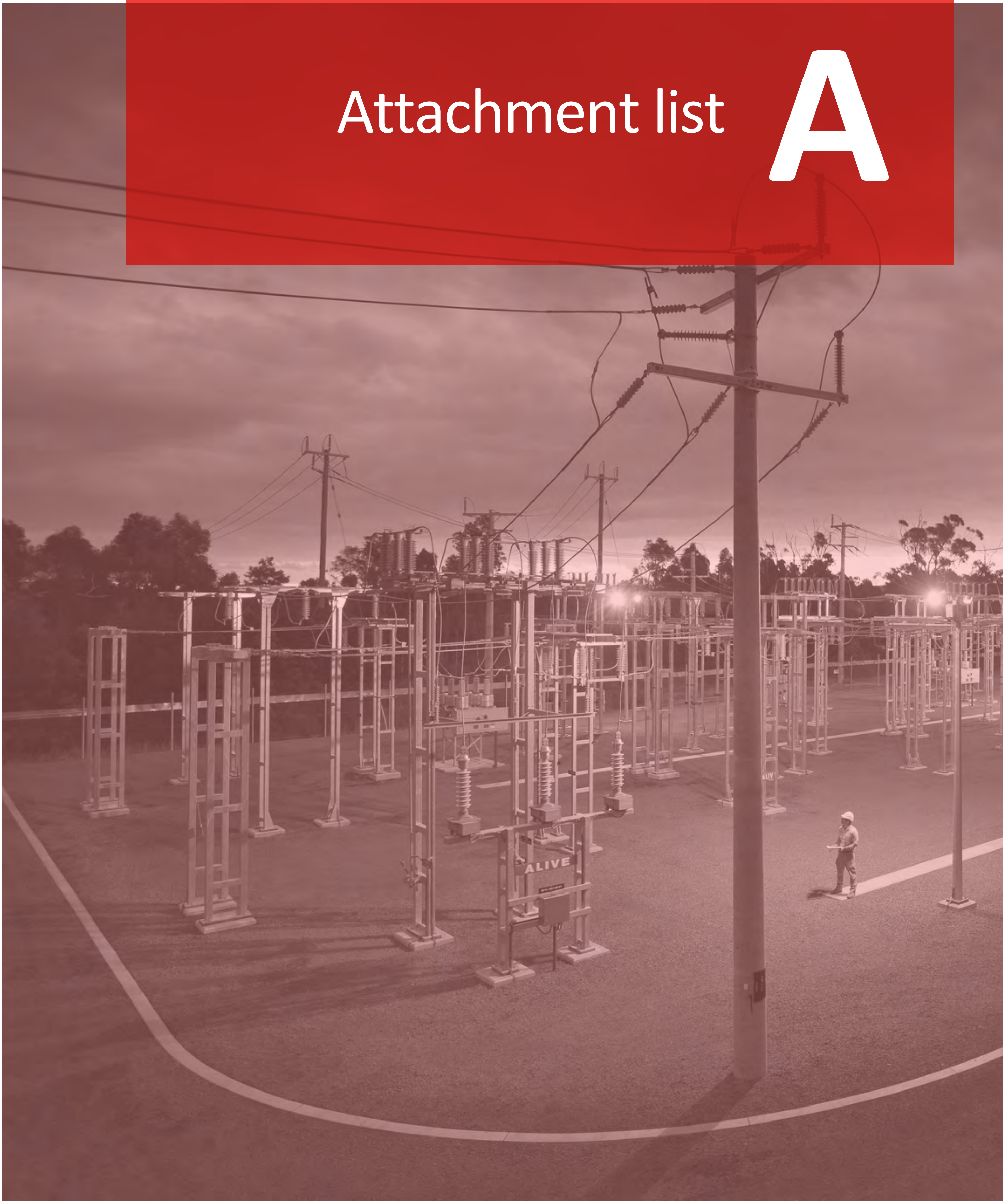
Attachment list

A



April 2018

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Table A.1 Attachment list

Attachment number	Title
REFCL2.01	Powercor, *BAN functional design scope*, April 2018
REFCL2.02	Powercor, *BAS functional design scope*, April 2018
REFCL2.03	Powercor, *BETS functional design scope*, April 2018
REFCL2.04	Powercor, *BGO functional design scope*, April 2018
REFCL2.05	Powercor, *CTN functional design scope*, April 2018
REFCL2.06	Powercor, *GL functional design scope*, April 2018
REFCL2.07	Powercor, *GL zone substation options analysis*, April 2018
REFCL2.08	Powercor, *HV customer scopes and detail* - CONFIDENTIAL, April 2018
REFCL2.09	Powercor, *Bushfire Mitigation Plan,* Revision 4.1b, 29 March 2017
REFCL2.10	Powercor, *XLPE cable review,* November 2017
REFCL2.11	Powercor, *Implementation and optimisation of REFCL systems*, March 2018
REFCL2.12	Marxsen Consulting Pty Ltd, *Customer Assets Directly Connected to REFCL networks: a preliminary risk survey*, 20 June 2017

Table A.2 Model list

Model number	Title
REFCL2_MOD.01	Powercor, *Expenditure build-up model (tranche two)*, April 2018
REFCL2_MOD.02	Powercor, *Amended PTRM*, April 2018
REFCL2_MOD.03	Powercor, *Amended depreciation model*, April 2018
REFCL2_MOD.04	Powercor, *Amended REPEX model*, April 2018

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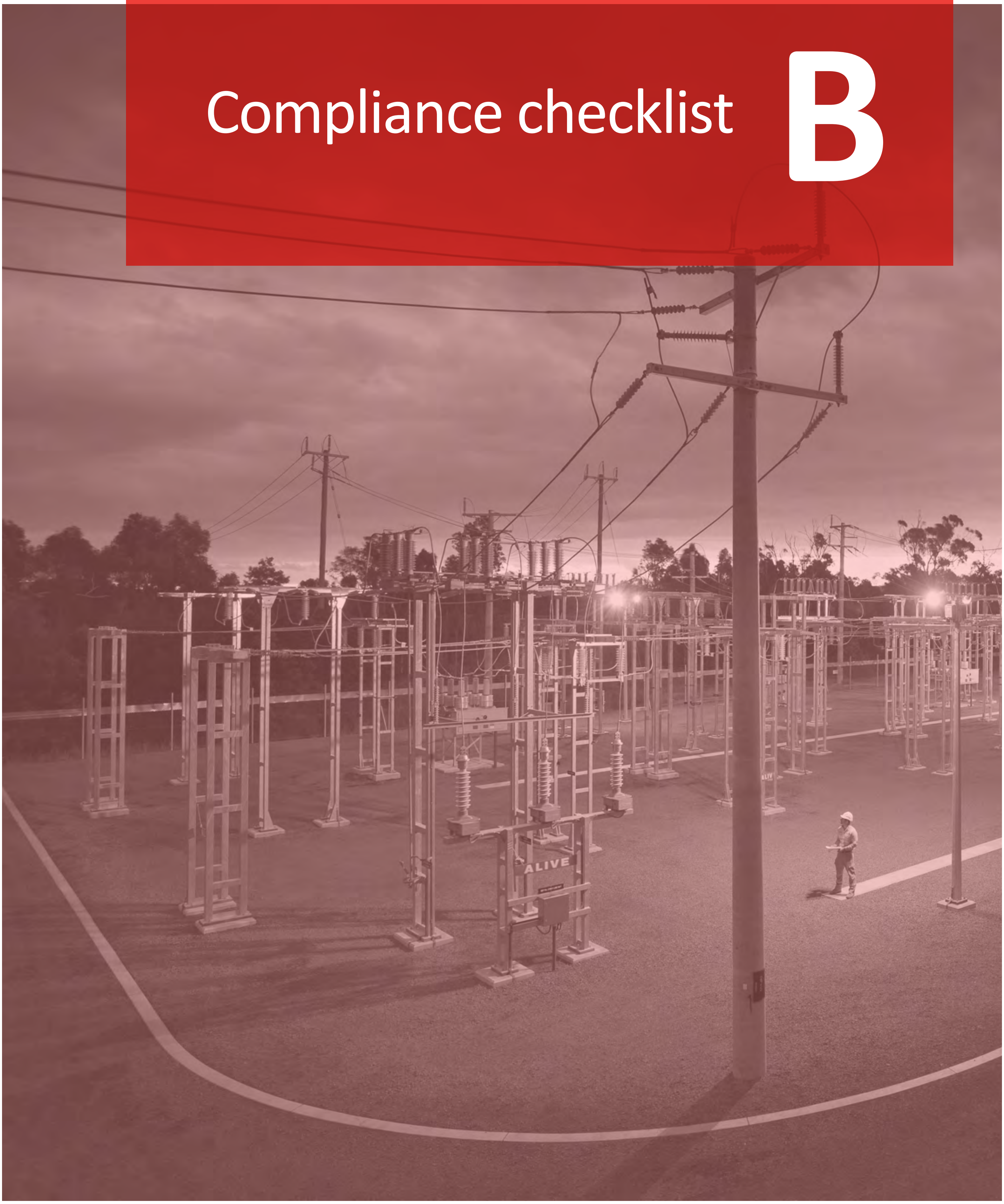
Compliance checklist

B



April 2018

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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; REFCL2_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 7.7; REFCL2_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 7.8; REFCL2_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 7.8; REFCL2_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 7.8; REFCL2_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 7.8; REFCL2_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 7.8; REFCL2_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 7.8; REFCL2_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 106