POWERCOR DISTRIBUTION ANNUAL PLANNING REPORT

CitiPower Pty Ltd and Powercor Australia Ltd

December 2023

Disclaimer

The purpose of this document is to provide information about actual and forecast constraints on Powercor's distribution network and details of these constraints, where they are expected to arise within the forward planning period. This document is not intended to be used for other purposes, such as making decisions to invest in generation, transmission or distribution capacity.

Whilst care was taken in the preparation of the information in this document, and it is provided in good faith, Powercor accepts no responsibility or liability for any loss or damage that may be incurred by any person acting in reliance on this information or assumptions drawn from it.

This Distribution Annual Planning Report (**DAPR**) has been prepared in accordance with the National Electricity Rules (**NER**), in particular Schedule 5.8, as well as the Victorian Electricity Distribution Code of Practice (VEDCoP).

This document contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and load growth forecasts that, by their nature, may or may not prove to be correct. This document also contains statements about Powercor's plans. These plans may change from time to time without notice and should therefore be confirmed with Powercor before any action is taken based on this document.

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1 Overview

The Distribution Annual Planning Report (**DAPR**) provides an overview of the current and future changes that Powercor proposes to undertake on its network. It covers information relating to 2023 as well as the forward planning period of 2024 to 2028.

Powercor is a regulated Victorian electricity distribution business. It distributes electricity to more than 920,000 homes and businesses in central and western Victoria, as well as Melbourne's outer western suburbs. Electricity is received via sub transmission lines at zone substations, where electricity is transformed from sub-transmission voltages to distribution voltages.

The report sets out the following information:

- forecasts, including capacity and load forecasts, at the zone substation, sub-transmission and primary distribution feeder level
- system limitations, which includes limitations resulting from the forecast load exceeding capacity following an outage, or retirements and de-ratings of assets
- projects that have been, or will be, assessed under the regulatory investment test
- other high level summary information to provide context to Powercor's planning processes and activities.

The DAPR provides a high-level description of the balance that Powercor will take into account between capacity, demand and replacement of its assets at each zone substation and sub-transmission line over the forecast period. This document should be read in conjunction with the System Limitation Reports and the Forecast Load Sheet. Transmission-distribution connection assets are addressed in a separate report.[1]

Data presented in this report may indicate an emerging major constraint, where more detailed analysis of risks and options for remedial action by Powercor are required.

The DAPR also provides preliminary information on potential opportunities to prospective proponents of non-network solutions at zone substations, sub-transmission lines and primary distribution feeders where remedial action may be required. Providing this information to the market facilitates the efficient development of the network to best meet the needs of customers.

The DAPR is aligned with the requirements of clauses 5.13.2(b) and (c) of the National Electricity Rules (**NER**) and contains the detailed information set out in Schedule 5.8 of the NER. In addition, the DAPR contains information consistent with the requirements of section

[1] Transmission-distribution connection assets are discussed in the Transmission Connection Planning Report which is available on the Powercor website at https://www.powercor.com.au/network-planning-and-projects/network-planning/

19.4 of the Victorian Electricity Distribution Code of Practice (VEDCoP), as published by the Essential Services Commission of Victoria.

1.1 Public consultation

Powercor invites written submissions from interested parties to offer alternative proposals to defer or avoid the proposed works associated with network constraints. All submissions should address the technical characteristics of non-network options provided in this DAPR and include information listed in the demand-side engagement strategy.

We also welcome feedback or suggestions for improvement on the structure or content presented in this year's DAPR or Systems Limitations Template.

All written submissions or enquiries should be directed to:

- DMInterestedParties@powercor.com.au

Alternatively, Powercor's postal address for enquiries and submissions is:

- Powercor
  Attention: Head of Network Planning and Development
  Locked Bag 14090
  Melbourne VIC 8001

2 Background

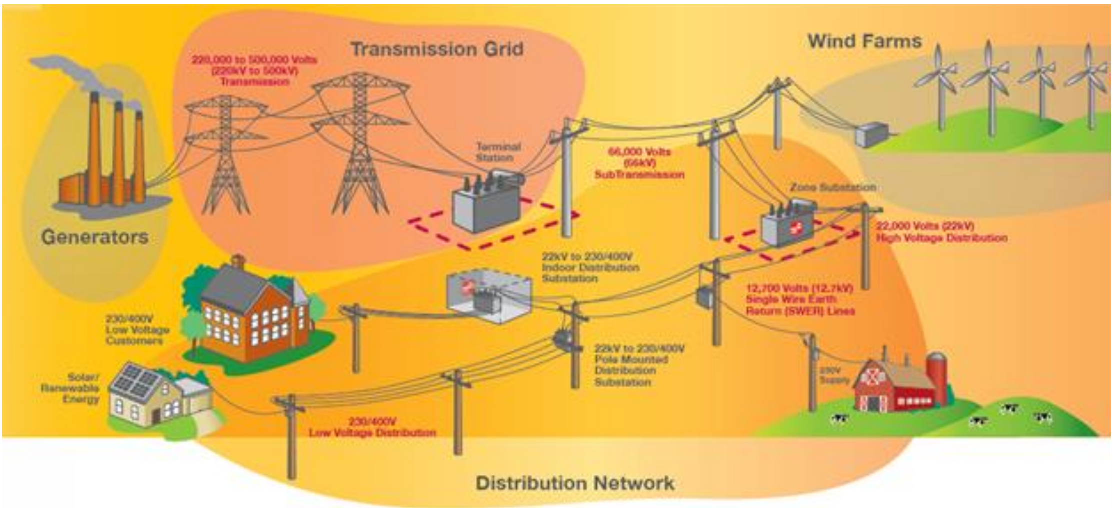
This chapter sets out background information on Powercor Australia Ltd (**Powercor**) and how it fits into the electricity supply chain.

2.1 Who we are

Powercor is a regulated Distribution Network Service Provider (**DNSP**) within Victoria. Powercor own the poles and wires which supply electricity to homes and businesses.

A high level picture of the electricity supply chain is shown in the diagram below.

Figure 2.1 The electricity supply chain



The distribution of electricity is one of four main stages in the supply of electricity to customers. The four main stages are:

- **Generation**: generation companies produce electricity from sources such as coal, wind or sun, and then compete to sell it in the wholesale National Electricity Market (**NEM**). The market is overseen by the Australian Energy Market Operator (**AEMO**), through the co-ordination of the interconnected electricity systems of Victoria, New South Wales, South Australia, Queensland, Tasmania and the Australian Capital Territory. It is recognised that a growing amount of generation is occurring at lower voltages including individual household photovoltaic (**PV**) arrays.

- **Transmission**: the transmission network transports electricity from generators at high voltage to five Victorian distribution networks. Victoria's transmission network also connects with the grids of New South Wales, Tasmania and South Australia.

- **Distribution**: distributors such as Powercor convert electricity from the transmission network into lower voltages and deliver it to Victorian homes and businesses. The major focus of distribution companies is developing and maintaining their networks to ensure a reliable supply of electricity is delivered to customers to the required quality of supply standards.

- **Retail**: the retail sector of the electricity market sells electricity and manages customer accounts. Retail companies issue customers' electricity bills, a portion of which includes regulated tariffs payable to transmission and distribution companies for transporting electricity along their respective networks.

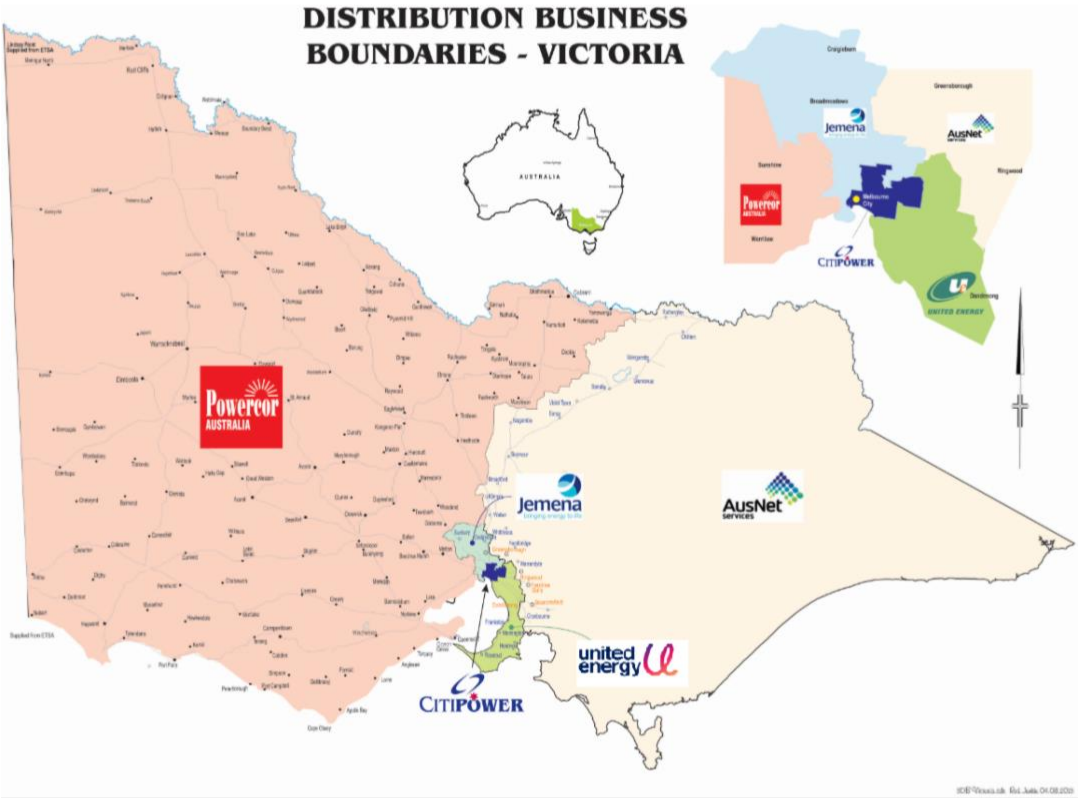
2.2 The five Victorian distributors

In the distribution stage of the supply chain, there are five businesses operating in Victoria. Each business owns and operates the electricity distribution network. Powercor is one of those distribution businesses.

The Powercor network provides electricity to customers in central and western Victoria, as well as Melbourne's outer western suburbs. Powercor supplies major regional centres including Ballarat, Bendigo and Geelong, and provides electricity to some of Australia's most popular tourist destinations, such as the towns along the Great Ocean Road.

The coverage of Powercor, and its related entity CitiPower, is shown in the figure below.

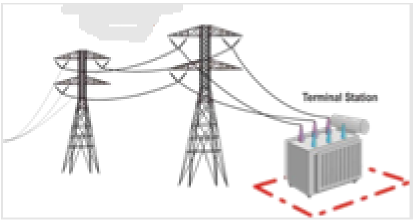
Figure 2.2 Powercor and other Victorian distribution areas



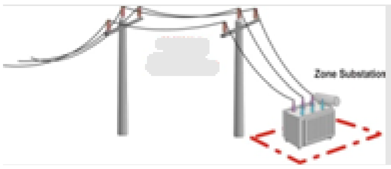
In Victoria, each DNSP has responsibility for planning the augmentation of their distribution network. In order to continue to provide efficient, secure and reliable supply to its customers, Powercor must plan augmentation and asset replacement of the network to match network capacity to customer demand. The need for augmentation is largely driven by customer peak demand growth and geographic shifts of demand due to urban redevelopment.

2.3 Delivering electricity to customers

Power that is produced by large-scale generators is transmitted over the high voltage transmission network and is changed to a lower voltage before it can be used in the home or industry. This occurs in several stages, which are simplified below.

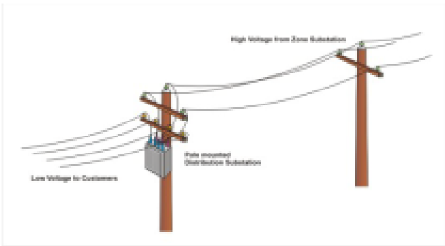


Firstly, the voltage of the electricity that is delivered to **terminal stations** is reduced by transformers. Typically in Victoria, most of the transmission lines operate at voltages of 500,000 volts (500 kilovolts or kV) or 220,000 volts (220kV). The transformer at the terminal station reduces the electricity voltage to 66kV. The Powercor network is supplied from the terminal stations.



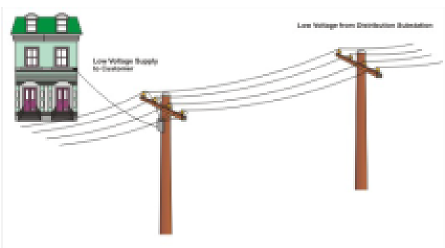
Second, Powercor distributes the electricity on the **sub-transmission system** which is made up of large concrete or wooden power poles and powerlines, or sometimes underground powerlines. The sub-transmission system transports electricity to Powercor's zone substations at 66kV.

Third, at the **zone substation** the electricity voltage is converted from 66kV to 22kV or 11kV. Electricity at this voltage can then be distributed on smaller, lighter power poles.



Fourth, **high voltage distribution lines** (or distribution feeders) transfer the electricity from the zone substations to Powercor's distribution substations.

Fifth, electricity is transformed to 400 / 230 volts at the **distribution substations** for supply to customers.



Finally, electricity is conveyed along the **low voltage distribution lines** to homes and businesses.

A growing amount of generation is occurring at lower voltages including individual customer level PV arrays.

2.4 Operating environment and asset statistics

Powercor delivers electricity to around 920,000 homes and businesses in a 145,651 square kilometre area, or around 6 customers per square kilometre.

Powercor's customer base comprises of large industrial and commercial customers through to small domestic and rural consumers. There are also a number of high voltage customer supplies and interconnection points for embedded generation such as wind farms and solar farms.

Powercor's electricity network comprises a sub-transmission network which consists of predominately overhead lines which operate at 66kV and a distribution network. The overall network consists of approximately 82 per cent overhead lines and 18 per cent underground cables that generally operate at 22kV. There is also some distribution network in Melbourne's western suburbs operating at a voltage of 11kV.

The sub-transmission network is supplied from a number of terminal stations which typically operate at a voltage of 220kV or greater. This transmission network, including the terminal stations, is owned and operated by AusNet Services and Transgrid.

The sub-transmission network nominally operates at 66kV and is generally configured in loops to maximise reliability, however some remote rural locations are supplied by radial 66kV lines. The sub-transmission network supplies electricity to zone substations which then transform (step down) the voltage suitable for the distribution to the surrounding area.

The distribution network consists of both overhead and underground lines connected to substations, switchgear, and other equipment to provide effective protection and control. Whilst the majority of the high voltage distribution system nominally operates at 22kV, there are notable exceptions:

- in remote and sparsely settled rural areas there is a substantial volume of Single Wire Earth Return (**SWER**) lines which operates at a nominal voltage of 12.7kV
- in the western suburbs of Melbourne, there are three smaller areas where the high voltage distribution system operates at a nominal voltage of 11kV
- in the far north west of the state, there a small system supplied from the South Australian network. This system operates at 33kV
- in the far south west of the state, there a small SWER system supplied from the South Australian network. This system operates at 19kV.

Distribution feeders are generally operated in a radial mode from their respective zone substation supply points. In urban areas, distribution feeders generally have inter-feeder tie points which can be reconfigured to provide for load transfers and other operational contingencies.

Powercor takes two supplies from the South Australian network at 33kV to supply the small townships of Nelson in the far south-west and at 19kV at Lindsay Point in the far north-west of the state. The Nelson supply is converted to 22kV at the state border.

The final supply to small consumers is provided through the low voltage distribution systems that nominally operate at 230 or 400 volts. These voltages are derived from "distribution substations" which are located throughout the distribution network and typically range in size from 5kVA to 2000kVA. Both overhead and underground low voltage reticulation, including service arrangements, complete the final connections to the low voltage consumer points of supply.

At the end of 2022-23FY, the Powercor network comprises approximately:

Table 2.1 Powercor network statistics

Item	Number / km
Poles	602,760
Overhead lines	76,601
Underground cables	16,371
Sub-transmission lines	136
Zone substation transformers	152
Distribution feeders	470
Distribution transformers	**88,573**

Error! Reference source not found. shows maps that indicate location of Powercor's zone substation assets and the connected terminal stations on a geographical basis.

3 Factors Impacting the Network

This chapter sets out the factors that may have a material impact on the Powercor network:

- **demand:** changes in demand causing thermal capacity constraints, such as that caused from population growth resulting in new residential customers connecting to the network, new or changed business requirements for electricity
- **fault levels:** the increasing amount of embedded generation being directly connected to the Powercor network is increasing the overall fault levels on the network which is reaching its fault level capacity in certain areas
- **voltage levels:** the long distance between the customer and the voltage regulating equipment means that lower voltage levels are observed on the Powercor network and need to be carefully managed
- **other system security requirements:** improvements in system security for single transformer zone substation, radial lines or zone substations with banked switching configuration will be considered when an increase in demand is forecast
- **quality of supply to other network users:** Powercor may carry out system studies on a case-by-case basis as part of the new customer connection process
- **ageing and potentially unreliable assets:** Powercor utilises a Health Index as a guide to determining the condition and therefore risk of asset failure
- **solar enablement:** Powercor's 'Solar Enablement' program of works is focused on limiting and mitigating issues related to high penetrations of solar PV
- **Rapid Earth Fault Current Limiters (REFCLs):** REFCLs are to provide safety benefits to the community through reduced risk of electrical assets contributing to starting a fire.
- **Distribution System Operator (DSO) enhanced capability:** To respond to the future challenges of the network at least cost, it is recognised that Powercor needs to implement and support new capabilities under an enhanced DSO role.
- **System Strength Locational Factor:** system strength locational factor represents the electrical distance of the embedded generation connection point to the system strength node

These factors are discussed in more detail below.

3.1 Demand

Changes in maximum demand on the network are driven by a range of factors. For example, this may include:

- **population growth:** increases in the number of residential customers connecting to the network
- **economic growth:** changes in the demand from small, medium and large businesses and large industrial customers
- **prices:** the price of electricity impacts the use of electricity
- **weather:** the effect of temperature on demand largely due to temperature sensitive loads such as air-conditioners and heaters
- **customer equipment and embedded generators:** the equipment that sits behind the customer meter including televisions, solar panels and batteries (which may mask the real demand behind the meter) and causing capacity constraints, pool pumps, electric vehicles, solar panels, wind turbines, batteries, etc.
- **electric vehicle chargers:** the increase in electric vehicles is increasingly causing a charging demand that could influence the maximum demand requirement.

Reductions in daytime minimum demand will become increasingly important for Powercor over time, as it is likely to compound existing voltage limitations when minimum demand is negative, with thermal capacity limitations on the electricity network. It is influenced by a couple of key factors including:

- **embedded generators:** increased adoption of solar PV systems by customers, is the primary contributor to reductions in daytime minimum demand. When power starts to reverse its flow upstream into the network due to solar PV exports, voltage and thermal capacity limitations may start to materialise; and
- **energy efficiency:** improved efficiency in customer appliances and in the behavioural use of those appliances reduces minimum demand.

Forecasting for demand is discussed later in this document.

3.2 Fault levels

A fault is an event where an abnormally high current is developed as a result of a failure of insulation somewhere in the network. A fault may involve one or more line phases and ground, or may occur between line phases only. In a ground/earth fault, charge flows into the earth or along a neutral or earth-return wire.

Powercor calculates the prospective fault current to ensure it is within allowable limits of the electrical equipment installed, and to enable the~~select and~~ selection and setting of the protective devices that can detect a fault condition. Devices such as circuit breakers, automatic circuit reclosers, sectionalisers, and fuses can act to break the fault current to protect the electrical plant and avoid significant and sustained outages as a result of plant damage.

Fault levels are determined according to a number of factors including:

- generation of all sizes
- impedance of transmission and distribution network equipment
- load including motors
- voltage

The following fault level limits are generally applied within the Powercor network:

Table 3.1 Fault level limits

Voltage	Fault limit (kilo Amps, kA)
66kV	21.9 kA
22kV	13.1 kA
11kV	18.4 kA
<1kV	50 kA

Where fault levels are forecast to exceed the allowable fault level limits, then fault level mitigation projects are initiated. This may involve, for example, introducing extra impedance into the network or separating network components that contribute to the fault such as opening the bus-tie circuit breakers at constrained zone substations to divide the fault current path.

Fault level mitigation programs are becoming increasingly common on the Powercor network as the level of embedded generation being directly connected to the network increases. This is because of the increasing fault level contribution from generators which the network was not designed for when originally conceived.

3.3 Voltage levels

Voltage levels are important for the operation of all electrical equipment, including home appliances with electric motors or compressors such as washing machines and refrigerators, or farming and other industrial equipment. These appliances are manufactured to operate within certain voltage threshold ranges.

Electricity distributors are obligated to maintain customer voltages within specified thresholds, and these are further discussed in section 17.2. Similarly, manufacturers can only supply such appliances and equipment that operate within the Australian Standards. Supply voltage at levels outside these limits could affect the performance or cause damage to the equipment as well as industry processes.

Voltage levels are affected by a number of factors including:

- generation of electricity into the network;

- impedance of transmission and distribution network equipment;
- length of sub-transmission or distribution feeders;
- implementation of REFCLs;
- load; and
- capacitors in the network.

The long distance between the customer and the voltage regulating equipment e.g. transformers and regulators means that lower voltage levels are observed on the Powercor network and need to be carefully managed. Powercor is actively monitoring lines susceptible to voltage issues.

In addition, groups of solar photovoltaic generators are increasingly causing fluctuations in voltage levels in localised areas. Powercor is monitoring the voltages in these areas. Higher voltage levels caused by solar generation are a particular concern.

3.4 System security

For zone substations and sub-transmission lines, the Powercor network may contain:

- single transformer at a zone substation;
- radial sub-transmission lines; and
- banked configuration of the transformers.

The use of a single transformer or a radial sub-transmission line generally occurs in remote areas of the network, typically with low demand. Where increases in demand are expected at the zone substation or on the line, then Powercor will consider improving the security of supply by installing an additional transformer or line.

When major augmentation is planned at a zone substation, Powercor will consider improving the switching configuration such that supply can be maintained without any intermittent loss of supply in the event of a transformer outage. For example, this can be achieved by isolating the faulty transformer automatically. This configuration is referred to as full switching as opposed to banked.

3.5 Quality of supply to other network users

Where embedded generators or large industrial customers are seeking to connect to the network and the type of load is likely to result in changes to the quality of supply to other network users, Powercor may carry out system studies on a case-by-case basis as part of the new customer connection process.

3.6 Potentially unreliable assets

Powercor carries out routine maintenance on its assets to reduce the probability of plant failure, and ensure they are fit for operation.

Assets with a high Health Index are a priority for Powercor and these are further discussed below.

3.6.1 Health Index

Powercor uses the Condition Based Risk Management **(CBRM)** methodology to plan any required interventions to manage risks associated with the performance of major items of plant and equipment.

The model is an ageing algorithm that takes into account a range of inputs including:

- condition assessment data, such as transformer oil condition
- environmental factors, such as whether the assets are located indoors or outdoors, or coastal areas
- operating factors, such as the load utilisation, frequency of use and load profiles that the asset is supplying.

These factors are combined to produce a Health Index for each asset in a range from 0 to 10, where 0 is a new asset and 10 represents end of life. The Health Index provides a means of comparing similar assets in terms of their calculated probability of failure.

Powercor will closely monitor assets with a Health Index in the range 5 to 7 to determine options for intervention, including replacement or retirement, in the context of energy at risk. Interventions are planned when an asset’s Health Index exceeds 5.5 and intervention prioritised when an asset’s Health Index exceeds 7.

A Health Index profile gives an immediate appreciation of the condition of all assets in a group and an understanding of the future condition of the assets. For the purposes of this DAPR, the Health Index of some assets has been provided where Powercor has assessed the risk to be sufficient to require intervention in the next five years.

As part of the CBRM process, a consequence of failure of the asset is also calculated. This assesses the consequence to customers due to loss of supply. The loss of a large amount of load (in MW) to a large industrial customer or to a large number of residential customers will indicate a high consequence of failure. This consequence of failure consists of four elements:

- network performance
- safety
- financial
- environment

The risk to Powercor is calculated by combining the probability of failure of the asset and the consequence of failure of the asset. CBRM is used to calculate how the risk will change in future years and determine the optimum timing for any intervention.

For the purposes of this DAPR, the Health Index of some assets has been provided where Powercor has assessed the risk to be sufficient to require intervention in the next five years.

3.7 Solar enablement

Distributed Energy Resources (particularly solar PV) connected to the network are creating voltage variations which are expected to significantly increase, in part due to penetration levels reaching a tipping point.

In areas with a higher proportion of solar customers, solar PV exports are causing the localised network voltage to rise during daylight hours. This can affect the quality of electricity supply to all customers in the area, trip solar customers' solar PV systems (from export and in-home-use) and raise network voltages above the limits set by the VEDCoP (Code).

Solar PV exports also have the potential to create capacity constraint concerns on the LV network. This is due to the increasing solar PV penetration, increasing average solar PV system sizes (to a point that where a customer's export capacity can exceed their load requirements) and the relatively low diversity of exports when compared to load diversity, for which the network was traditionally designed to accommodate.

Powercor's delivery of its 5-year 'Solar Enablement' program of works is focused on limiting and mitigating issues related to high penetrations of solar PV. Works include:

- implementation of a Dynamic Voltage Management System (DVMS) to enable increased solar hosting capacity by dynamically adjusting system voltages in real time based on feedback from AMI meters installed at each customer premise. This has been commissioned at the majority of Powercor zone substations progressively from March to November 2022.
- completion of an annual program of network interventions such as phase rebalancing, distribution transformer tapping, distribution transformer replacement and undertaking conductor works and replacements

Further works involving high and low voltage interventions and system upgrade activities are planned for 2024, including:

- continued engagement with manufacturers, installers, and customers that have identified issues, to rectify solar PV installations and inverter setting issues, and improve installation compliance going forward
- DVMS enhancements and implementing at other voltage control zones outside of Powercor zone substations

3.8 Rapid Earth Fault Current Limiters (REFCLs)

This section sets out Powercor's plans to install Rapid Earth Fault Current Limiters (REFCLs) in the network. The purpose of installing REFCLs is to provide safety benefits to the community through reduced risk of electrical assets contributing to starting a fire.

A REFCL is a network protection device, normally installed at a zone substation that can reduce the risk of a fallen powerline or a powerline indirectly in contact with the earth causing a fire-start. It is capable of detecting when a powerline falls to the ground and almost instantaneously reduces the voltage to near-zero on the fallen line.

Customers that are directly connected to Powercor's 22kV high voltage (HV) network may need to take action in response to Powercor's REFCL deployment program

For Powercor, the installation of REFCLs also ensures compliance with the amendments to the *Electricity Safety (Bushfire Mitigation) Regulations 2023* (Regulations) which were implemented in Victoria on 1 May 2016.

The Regulations require each polyphase electric line originating from 45 specified zone substations (22 of which are Powercor zone substations) to comply with performance standards specified in the Regulations. Schedule two of the Regulations assigns a number of 'points' to each of the specified zone substations. Powercor is required to ensure that:

- at 1 May 2019, the points set out in schedule two to the Regulations in relation to each zone substation upgraded, when totalled, were not less than 30
- at 1 May 2021, the points set out in schedule two in relation to each zone substation upgraded, when totalled, were not less than 55
- from 1 May 2023, in the Powercor supply network, each polyphase electric line originating from every zone substation specified in schedule two has the required capacity.

3.8.1 Zone substations

In 2023, Powercor commissioned REFCLs at Gheringhap (**GHP**).

On 20 August 2018, the Essential Services Commission of Victoria (**ESCV**) amended the Distribution Code which had the impact of transferring responsibility from distributors to HV customers for hardening of the HV customer assets to withstand the higher REFCL voltages or isolating the connection from the network when a REFCL operates. For all zone substations where REFCLs will be commissioned from 2020, HV customers will need to take action to:

- ensure that their assets are compatible with the operation of a REFCL
- complete any required works prior to the commissioning of the relevant Powercor REFCL zone substation.

The table below sets out the ongoing REFCL work to maintain compliance including the proposed upgrade and/or commissioning date.

Table 3.2 Commissioning year for ongoing REFCL work

Zone substation	Project description	Year	Status
Woodend (**WND**)	Feeder rearrangement	2024	Planned for 2024
Ballarat South (**BAS**)	New isolating substation	2024	Planned for 2024
Ballarat East (**BAE**)	New zone substation with transformer and REFCL	2025	In plan

Colac (**CLC**)	New isolating substation with REFCL	2025	In plan
Ararat (**ART**)	New isolating substation	2026	In plan
Gisborne (**GSB**)	Additional REFCL	2026	In plan
Ballarat East (**BAE**)	New transformer and additional REFCL	2027	In plan
Eaglehawk (**EHK**)	New transformer and additional REFCL	2027	In plan
Bendigo (**BETS**)	Feeder rearrangement	2028	In plan
Colac (**CLC**)	New isolating substation with REFCL	2028	In plan
Gheringhap (**GHP**)	Feeder rearrangement	2028	In plan

The table below sets out the proposed commissioning date for the planned installation of REFCLs over the next five years in the following substations.

Table 3.3 Commissioning year for REFCLs

Zone substation	Year
Gheringhap (**GHP**)	2023

Note that Geelong (**GL**) and Corio (**CRO**) zone substations have been removed from the program after an exemption was granted to build a new, complying zone substation west of Geelong. This substation was constructed at Gheringhap (**GHP**). Torquay (**TQY**) was commissioned in conjunction with Waurn Ponds (**WPD**) as the capacitance of the network had grown considerably since the REFCL legislation was introduced beyond the rating of the REFCL's proposed for Waurn Ponds (**WPD**) zone substation.

3.8.2 Other impacted areas of the network

The installation of a REFCL at a zone substation can impact other parts of the Powercor network. Generally, the REFCL would only impact the 22kV HV feeders directly connected to the REFCL zone substation. During contingent events, however, the open points on the network may change resulting in feeders connected to non-REFCL zone substations being served from a REFCL zone substation and thus experiencing the higher voltages associated with the operation of a REFCL. Part of Powercors work has therefore been to ensure that any tie feeders that are normally used to support REFCL feeders are also able to operate safely during contingency events.

New or existing HV customers connected to the feeders listed below, which may experience a REFCL condition during contingent events, are also required to take action to:

- ensure that their assets are compatible with the operation of a REFCL

- complete any required works prior to the commissioning of the relevant Powercor REFCL zone substation.

Table 3.4 Other impacted areas of the network

Year	2023
Feeders	CRO013, CRO022, GL012, GL014, GL015 (from GHP)

Any new HV customer assets connecting to this network will be required to be compatible with the operation of a REFCL.

3.9 Distribution System Operator (DSO) enhanced capability

To respond to the future challenges of the network at least cost, it is recognised that Powercor needs to implement and support new capabilities under an enhanced DSO role. Information Technology (**IT**) investments in this area have been articulated in Chapter 19 Information Technology and Communication Systems. These capabilities are broadly around the workstreams of:

- enabling DER export and increasing hosting capacity whilst addressing minimum demand and other system security obligations that may be placed on the distributor
- utilising batteries to manage constraints and value stacking arrangements with third parties to demonstrate multiple benefits
- enabling competition for non-network solutions through expanded platforms for sharing network constraints
- developing Dynamic Operating Envelope capability that is flexible to more dynamically enable solar PV exports for customers based on current network capacity and demand, manage the network and enable third party service offerings on the distribution network

Chapter 18.2 details the specific projects that Powercor is delivering in terms of demand management and non-network solutions.

3.10 System Strength Locational Factor

In October 2021, the AEMC made its final rule determination on efficient management of system strength on power system. The Rule introduces a new way for system strength remediation in the NEM, allowing the embedded generators to either pay for system strength charges or self remediation. The system strength locational factor represents the electrical distance of the embedded generation connection point to the system strength node (a location on a transmission network that AEMO declares under NER clause 5.20C.1(a)) and is used to calculate the system strength charge in accordance with the methodology in the AEMO's System Strength Impact Assessment Guidelines[2].

Under NER Schedule 5.8 (q), the system strength location factor information for each embedded generation (or generating system) in PAL network in which the embedded generation system has elected to pay the system strength charge under clause 5.3.4B(b1) is to be included in this report.

PAL currently does not have any embedded generator in its network that has elected to pay system strength charge for the purpose of system strength remediation.

[2] AEMO | System Strength Impact Assessment Guidelines available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/system-strength-impact-assessment-guidelines

4 Network Planning Standards

This chapter sets out the process by which Powercor identifies maximum and minimum demand-driven limitations in its network.

4.1 Approaches to planning standards

In general, there are two approaches to network planning:

Deterministic planning standards: this approach calls for zero interruptions to customer supply (or no curtailment of embedded generation) following any single outage of a network element, such as a transformer. In this scenario any failure or outage of individual network elements (known as the “N-1” condition) can be tolerated without customer impact due to sufficient resilience built into the distribution network. A strict use of this approach may lead to inefficient network investment as resilience is built into the network irrespective of the cost of the likely interruption to the network customers (or the cost of curtailing generation), or use of alternative options.

Probabilistic planning approach: the deterministic N-1 criterion is relaxed under this approach, and simulation studies are undertaken to assess the amount of energy that would not be supplied (or the amount of energy that would need to be forcibly curtailed) if an element of the network is out of service. As such, the consideration of energy not served may lead to the deferral of projects that would otherwise be undertaken using a deterministic approach. This is because:

- under a probabilistic approach, there are conditions under which all the load cannot be supplied (or some generation needs to be curtailed) with a network element out of service (hence the N-1 criterion is not met), however
- the actual energy at risk may be very small when considering the probability of a forced outage of a particular element of the sub-transmission network.

In addition, the probabilistic approach assesses energy at risk under system normal conditions (known as the “N” condition). This is where all assets are operating but the demand breaches either the total import or export capacity. Contingency transfers may be used to mitigate energy at risk in the interim period until it is economically prudent for an augmentation to be completed.

4.2 Application of the probabilistic approach to planning

Powercor adopts a probabilistic approach to planning its zone substation and sub-transmission asset augmentations.

The probabilistic planning approach involves estimating the probability of an outage occurring during periods of high import or export, and weighting the costs of such an occurrence by its probability, to assess:

- the expected cost that will be incurred if no action is taken to address an emerging constraint, and therefore
- whether it is economic to augment the network capacity to reduce that expected cost.

The quantity and value of energy at risk (which is discussed in section 6.1) is a critical parameter in assessing a prospective network investment or other action in response to an emerging limitation. Probabilistic network planning aims to ensure that an economic balance is struck between:

- the cost of providing additional network capacity to remove limitations
- the cost of having some exposure to demand levels beyond the network's capability to import or export power.

In other words, recognising that very extreme demand conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that an outage of an item of network plant may occur at the same time. The probabilistic approach requires expenditure to be justified with reference to the expected benefits of lower unserved energy.

This approach provides a reasonable estimate of the expected net present value to consumers of network augmentation for planning purposes. However, implicit in its use is acceptance of the risk that there may be circumstances (such as the loss of a transformer at a zone substation during a period of high demand) when the available network capacity will be insufficient to meet the actual demand for the network and significant load shedding or generation curtailment could be required. The extent to which investment should be committed to mitigate that risk is ultimately a matter of judgment, having regard to:

- the results of studies of possible outcomes, and the inherent uncertainty of those outcomes
- the potential costs and other impacts that may be associated with very low probability events, such as single or coincident transformer outages at times of maximum or minimum demand, and catastrophic equipment failure leading to extended periods of plant non-availability

the availability and technical feasibility of cost-effective contingency plans and other arrangements for management and mitigation of risk.

5 Forecasting Demand

This chapter sets out the methodology and assumptions for calculating historical and forecast levels of demand for each existing zone substation and sub-transmission system. These forecasts are used to identify potential future constraints in the network.

Please note that information relating to transmission-distribution connection points are provided in a separate report entitled the “Transmission Connection Planning Report” which is available on the Powercor website.[3]

5.1 Maximum and minimum demand forecasts

Powercor has set out its forecasts for maximum and minimum demand for each existing zone substation and sub-transmission system in the Forecast Maximum and Minimum Demand Sheet.

5.2 Zone substation methodology

This sub-section sets out the methodology and information used to calculate the demand forecasts and related information that is referred to in the Forecast Maximum and Minimum Demand Sheet and System Limitation Reports.

5.2.1 Historical demand

Historical demand is calculated in Mega Volt Ampere (**MVA**) and is based on actual maximum and minimum and demand values recorded across the distribution network.

As maximum and minimum demand in Powercor is very temperature and weather dependent, the actual maximum and minimum demand values referred to in the Forecast Maximum and Minimum Demand Sheet are normalised for the purpose of forecasting, in accordance with the relevant weather conditions experienced across any given summer loading period. The correction enables the underlying maximum and minimum demand growth year-by-year to be estimated, which is used in making future forecast and investment decisions.

The temperature correction for the maximum demand forecast seeks to ascertain the “*50th percentile maximum demand*”. The 50th percentile demand represents the maximum demand on the basis of a normal season (summer and winter). It relates to a maximum average temperature that will be exceeded, on average, once every two years. It is often referred to as 50 per cent probability of exceedance (**PoE**).

[3] https://www.powercor.com.au/what-we-do/the-network/network-planning/

The weather correction for the minimum demand forecasts presented in this DAPR seeks to ascertain the "*50th percentile annual minimum demand*". The 50th percentile demand represents the minimum demand on the basis of a weather condition that would lead to a one-in-two year minimum demand, dictated primarily by the amount of cloud cover impacting solar PV output embedded within the distribution network.

5.2.2 Forecast demand

Historical demand values taking into account local generation inputs are trended forward and added to known and predicted loads that are to be connected to the network. This includes taking into account the number of customer connections and the calculated total output of known embedded generating units.

Powercor has taken into account information collected from across the business relating to the load requirements of our customers, and the timing of those loads. This includes population growth and economic factors as well as information on the estimated load requirements for planned, committed and developments under-construction across the Powercor service area. Powercor has also taken into account information relating to DER installations by our customers.

These bottom-up forecasts for demand have been reconciled with top–down independent econometric forecasts for Powercor as a whole.

These forecasts are referred to in the Forecast Maximum and Minimum Demand Sheet.

5.2.3 Definitions for zone substation forecast tables

The Forecast Maximum and Minimum Demand Sheet refers to other statistics of relevance to each zone substation, including:

- **N import (or export) rating**: this provides the maximum capacity of the zone substation according to the equipment in place (for forward and reverse power flows respectively) up to its nameplate value
- **Cyclic N-1 import rating**: this assumes that the net load follows a daily pattern and is calculated using net load curves appropriate to the season and assuming the outage of one transformer. This is also known as the "firm" rating;
- **N-1 export rating**: this provides the capacity of the zone substation according to the equipment in place up to its nameplate value and assuming the outage of one transformer. This is also known as the "firm" export rating;
- **Hours load is ≥ 95% of maximum (or minimum) demand** (**MD**): based on at least the most recent 12 months of data, assesses the net load duration curve and the total hours during the year that the net load is greater than or equal to 95 per cent of maximum or minimum demand
- **Station power factor at maximum (or minimum) demand (MD):** based on the most recent maximum or minimum demand achieved in a season at the zone substation, this is a measure of how effectively the current is being converted into output and is also a good indicator of the effect of the current on the efficiency of the supply system. It is calculated as a ratio of real power and apparent power and is used to inform demand forecasts. A power factor of:

- less than one: indicates a lagging or leading current in the supply system which may need correction, such as by increasing or reducing capacitors at the zone substation
- one: efficient loading of the zone substation;

- **Load transfer capacity**: forecasts the available capacity of adjacent zone substations and feeder connections to take load away from the zone substation in emergency situations
- **Generation capacity**: calculates the total capacity of all embedded generation units that have been connected to the zone substation at the date of this report. Summation of generation above and below 1MW is provided.

5.3 Sub-transmission line methodology

This section sets out the methodology for calculating the historical and forecast maximum and minimum demands for the sub-transmission lines.

5.3.1 Historical demand

The sub-transmission line historical N-1 maximum and minimum demands for different line configurations are determined using a power flow analysis tool called Power System Simulator for Engineering (**PSS/E**).

The tool models the sub-transmission line from the terminal station to the zone substation to determine the theoretical N-1 maximum and minimum demand, by utilising historical actual demands and assessing:

- system impedances;
- transformer tapping ratios, which are used to regulate the transformer voltages;
- capacitor banks; and
- other technical factors relevant to the operation of the system.

The historical maximum and minimum demand data for the relevant zone substations is applied to the load flow analysis to enable calculation of the theoretical N-1 maximum and minimum demand of the sub-transmission line.

The zone substation forecast maximum and minimum demands are diversified to the expected zone substation demands at the time of the respective sub-transmission loop/ line maximum and minimum demand. Historical diversity factors are derived and applied.

The data is used to assess the maximum and minimum demand in the worst case “N-1” conditions. This is for a single contingency condition where there is the loss of an element in the power system, in particular the loss of another associated sub-transmission line. For a zone substation the demand is identical whether the zone substation is operating under N or N-1 (loss of a transformer). Therefore the N-1 cyclic import or export rating (as appropriate) is used to compare against the demand forecast. However for the loss of a sub-transmission line, other associated lines are loaded more heavily so it is appropriate to consider the N-1 condition for the forecast and compare to the line import or export rating (as appropriate).

5.3.2 Forecast demand

Similar to the sub-transmission line historical maximum and minimum demand loads, bottom-up forecasts for maximum and minimum demand are predicted utilising a powerflow analysis tool, PSS/E for different line configurations.

The present sub-transmission system is modelled from the terminal stations to the zone substations, taking into account system impedances, transformer tapping ratios, voltage settings, capacitor banks and other relevant technical factors.

The reconciled maximum and minimum demand forecasts at each zone substation are used in calculating the maximum and minimum demand forecasts for the sub-transmission lines. As discussed in section 5.2 above, the bottom-up forecasts for demand at each zone substation have been reconciled with top–down independent econometric forecasts.

The zone substation forecast maximum and minimum demands are diversified based on the historical diversity factors mentioned above.

The data is used to forecast the maximum and minimum demand under “N-1” conditions. These forecasts are referred to in the Forecast Maximum and Minimum Demand Sheet.

5.3.3 Definitions for sub-transmission line forecast tables

The Forecast Maximum and Minimum Demand Sheet refers to other statistics of relevance to each sub-transmission line, including:

- **Line import (or export) rating**: this provides the maximum capacity of the sub-transmission line (for forward and reverse power flows respectively) as measured by its current and expressed in MVA;
- **Hours load is ≥ 95% of maximum (or minimum) demand** (**MD**): based on at least the most recent 12 months of data, assesses the load duration curve and the total hours during the year that the load is greater than or equal to 95 per cent of maximum or minimum demand;
- **Power factor at maximum (or minimum) demand (MD):** based on historical data**,** is a measure of how effectively the current is being converted into output and is also a good indicator of the effect of the load current on the efficiency of the supply system. It is calculated as a ratio of real power and apparent power and is used to inform demand forecasts. A power factor of:
    - less than one: indicates a lagging or leading current in the supply system which may need correction, such as by increasing or reducing capacitors at the zone substation;
    - one: efficient loading of the zone substation.
- **Load transfer capacity**: forecasts the available capacity of alternative sub-transmission lines that can carry electricity to the zone substation in emergency situations; and
- **Generation capacity**: calculates the total capacity of all embedded generation that have been directly connected to the sub-transmission line at the date of this report.

5.4 Transmission-distribution connection points methodology

This subsection sets out the methodology and information used to calculate the demand forecasts and related information that is referred to in the Forecast Maximum and Minimum Demand Sheet, Transmission Connection Planning Report and System Limitation Reports.

5.4.1 Historical demand

Historical demand is calculated in Mega Volt Ampere **(MVA)** and is based on actual maximum and minimum demand values recorded at each terminal station.

As maximum and minimum demand in Powercor is very temperature and weather dependent, the actual maximum and minimum demand values referred to in the Forecast Maximum and Minimum Demand Sheet and the Transmission Connection Planning Report are normalised for the purpose of forecasting, in accordance with the relevant weather conditions experienced across any given period. The correction enables the underlying maximum and minimum demand growth year-by-year to be estimated, which is used in making future forecast and investment decisions.

5.4.2 Forecast demand

Historical demand values taking into account local generation inputs are trended forward, and adjusted for the changes in the zone substation growth rates of the zone substations connected to that terminal station. These bottom-up forecasts for demand are reviewed against AEMO’s connection point forecasts.

These forecasts are set out in the Forecast Maximum and Minimum Demand Sheet and the Transmission Connection Planning Report.

5.4.3 Definitions for transmission-distribution connection point forecast tables

The Forecast Maximum and Minimum Demand Sheet and the Transmission Connection Planning Report contains other statistics of relevance to each terminal station, including:

- **N import (or export) rating**: this provides the maximum capacity of the terminal station according to the equipment in place (for forward and reverse power flows respectively) up to its nameplate value;
- **Cyclic N-1 import (or export) rating**: this assumes that the net load follows a daily pattern and is calculated using net load curves appropriate to the season and assuming the outage of one transformer (for forward and reverse power flows respectively). This is also known as the “firm” rating;
- **Hours 95% of maximum (or minimum) demand**: based on at least the most recent 12 months of data, assesses the net load duration curve and the total hours during the year that the net load is greater than or equal to 95 per cent of maximum or minimum demand;
- **Station power factor at maximum (or minimum) demand:** based on the most recent maximum or minimum demand achieved in a season at the terminal station, this is a measure of how effectively the current is being converted into output and is also a good indicator of the effect of the current on the efficiency of the supply system. It is

calculated as a ratio of real power and apparent power and is used to inform demand forecasts. A power factor of:

  - less than one: indicates a lagging or leading current in the supply system which may need correction, such as by increasing or reducing capacitors at the terminal station;
  - one: efficient loading of the terminal station;

- **Load transfer capacity**: forecasts the available capacity of adjacent terminal stations, sub-transmission lines and feeder connections to take load away from the terminal station in emergency situations; and
- **Generation capacity**: calculates the total capacity of all embedded generation units that have been connected to the terminal station at the date of this report. Summation of generation above and below 1MW is provided.

Further information on transmission-distribution connection points is reported in the "Transmission Connection Planning Report".

5.5 Primary distribution feeders

This section sets out the methodology for calculating the forecast maximum demands for the primary distribution feeders.

5.5.1 Forecast demand

Primary distribution feeder maximum and minimum demand forecasts are calculated using a similar methodology to our zone substation forecasts. The historical feeder demand values are trended forward using the underlying feeder growth rates including known or predicted loads and embedded generators that are forecast for connection.

Weather correction and top down reconciliation occurs on the feeder and zone substation forecasts and is therefore inherent in the sub-transmission forecasts.

6 Approach to Risk Assessment

This chapter outlines the high level process by which Powercor calculates the risk associated with the expected balance between capacity and demand over the forecast period for zone substations and sub-transmission lines.

This process provides a means of identifying those stations or lines where more detailed analyses of risks and options for remedial action are required.

6.1 Energy at risk

As discussed in section 4.1, risk-based probabilistic network planning aims to strike an economic balance between:

- the cost of providing additional network capacity to remove any limitations; and
- the potential cost of having some exposure to demand levels beyond the network's firm capability to import or export power.

A key element of this assessment for each zone substation and sub-transmission line is "energy at risk", which is an estimate of the amount of energy that would not be supplied to load, or would need to be curtailed from embedded generators, if one transformer or a sub-transmission line was out of service during the critical loading period(s).

For zone substations, **energy at risk** is defined as, the amount of energy that would not be supplied to load during periods of maximum demand, or would need to be curtailed from embedded generators during periods of minimum demand, from a zone substation if a major outage[5] of a transformer occurs at that station in that particular year, and no other mitigation action is taken.

This measure provides an indication of the magnitude of loss of load (or forced curtailment of generation) that would arise in the unlikely event of a major outage of a transformer without taking into account planned augmentation or operational action, such as load transfers to other supply points, to mitigate the impact of the asset outage.

For sub-transmission lines, the same definition applies however, the mean duration of an outage due to a significant failure is 8 hours for overhead sub-transmission lines and 1 week for underground sub-transmission lines.

5 The term 'Major Outage' refers to an outage that has a duration of 2.6 months, typically due to a significant failure within the transformer.

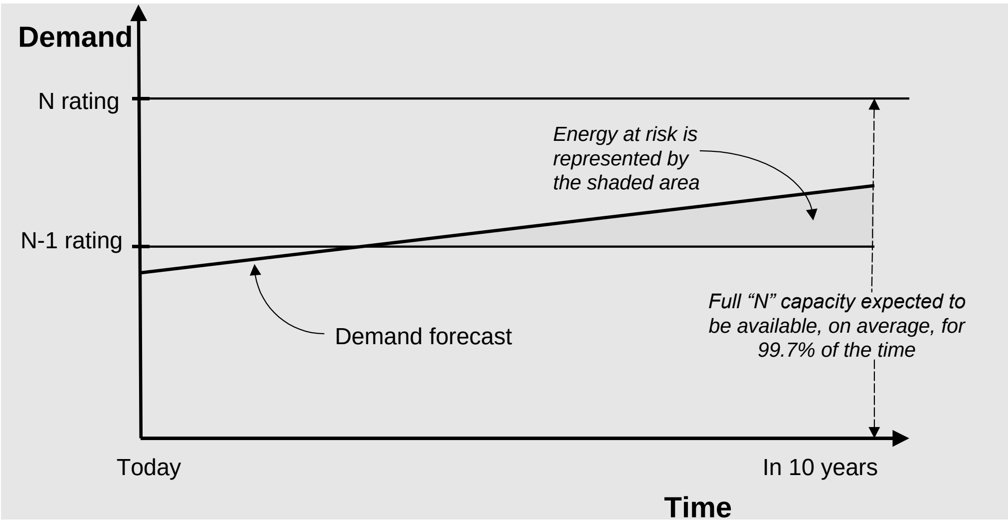
6.2 Interpreting “energy at risk”

As noted above, “energy at risk” is an estimate of the amount of energy that would not be supplied to load, or would need to be curtailed from embedded generators, if one transformer or sub-transmission line was out of service during a critical import or export loading condition, respectively.

The capability of a zone substation with one transformer out of service is referred to as its “N minus 1” rating. The capability of the station with all transformers in service is referred to as its “N” rating. When a zone substation is importing power (i.e., power flowing towards the customer load), the import rating applies. When a zone substation is exporting power (i.e., power flowing towards the transmission network), the export rating applies.

The relationship between the N and N-1 cyclic ratings of a station and the energy at risk (assuming maximum demand conditions) is depicted in Figure 6.1 below:

Figure 6.1 Relationship between N, N-1 cyclic ratings and energy at risk



Note that:

- Under normal operating conditions, there will typically be more than adequate zone substation capacity to supply all demand. The risk of prolonged outages of a zone substation transformer leading to load interruption is typically very low.
- The capability of a sub-transmission line network with one line out of service is referred to as the (N-1) condition for that sub-transmission network. Under normal operating conditions, there will typically be more than adequate line capacity to supply all demand.
- The risk of prolonged outages of a sub-transmission line leading to load interruption is typically very low and is dependent upon the length of line exposed and the environment in which the line operates.

In estimating the expected cost of plant outages, this report considers the first order contingency condition (“N-1”) only.

6.3 Valuing supply reliability from the customer's perspective

For large augmentation or replacement projects over $6 million that are subject to a Regulatory Investment Test for Distribution (**RIT-D**), Powercor will undertake a detailed assessment process to determine the most efficient solution.

In order to determine the economically optimal level and configuration of distribution capacity (and hence the supply reliability that will be delivered to customers), it is necessary to place a value on supply reliability from the customer's perspective.

Estimating the marginal value to customers of reliability is inherently difficult, and ultimately requires the application of some judgement. Nonetheless, there is information available (principally, surveys designed to estimate the costs faced by customers as a result of electricity supply interruptions) that provides a guide as to the likely value.

A rule change in July 2018 made the Australian Energy Regulator (**AER**) responsible for determining the values different customers place on having a reliable electricity supply. The AER subsequently developed an updated methodology for deriving Value of Customer Reliability (**VCR**) values and published new VCRs in December 2022. The applicable Powercor VCR values from this publication are as per Table 6.1 below:

Table 6.3 Values of customer reliability used in this DAPR

Sector	VCR for 2022 ($/kWh)
Residential	$22.23
Commercial	$46.18
Agricultural	$39.28
Industrial (<10MVA)	$66.17

These values are multiplied by the relative weighting of each sector at the zone substation or for the sub-transmission line, and a composite single value of customer reliability is estimated. This data is used to calculate the economic benefit of undertaking an augmentation, and where the net present value of the benefits outweighs the costs, and is superior to other options, Powercor will proceed with the works.

Powercor notes that there has been a reduction in the VCR estimates for the residential, commercial and agricultural sectors while a significant increase for the industrial sector compared to the results of the 2019 VCR study, which was published in AEMO's 2019 Application Guide.

From a planning perspective, it is appropriate for Powercor to have regard to the latest available VCR estimates. It is also important to recognise, however, that all methods for estimating VCR are prone to error and uncertainty, as illustrated by the wide differences between:

- AEMO's VCR estimate for 2013 of $63 per kWh, which was based on the 2007/08 VENCorp study[6]

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[6] See section 2.4 of the 2013 Transmission Connection Planning Report.

- Oakley Greenwood's 2012 estimate of the New South Wales VCR[7], of $95 per kWh
- AER's latest Victorian VCR[8] estimate of $40.73 per kWh.

The wide range of VCR estimates produced by these three studies is likely to reflect estimation errors and methodological differences between the studies, rather than changes in the actual value that customers place on reliability. Moreover, the magnitude of the reduction in AEMO's VCR estimates since 2013 raises concerns that the investment decisions signalled by applying the current VCR estimate may fail to meet customers' reasonable expectations of supply reliability.

6.4 Generation curtailment

On 12 August 2021, the AEMC made a final determination on its "Access, pricing and incentive arrangements for distributed energy resources" Rule change[9]. Under the Rule change, the AER is required to develop customer export curtailment values ("CECV"), which are an estimate of the detriment to customers and the market of export curtailment due to network limitations (in $ per kWh of exports curtailed). CECVs are expected to play a similar role to the VCR in evaluating the net benefit of reducing or removing network constraints. For instance, it is expected that the CECVs will be used to assess whether proposed steps to reduce export curtailment (such as increasing DER hosting capacity) can be economically justified.

In June 2022, the AER published its Customer Export Curtailment Value Methodology. At the same time, the AER also published a DER Integration Expenditure Guidance Note[10], which includes direction on how distribution network service providers should i) develop business cases for network investment integrating higher levels of customer DER and quantify DER values, ii) develop DER integration plans and investment proposals, and ii) quantify DER benefits in a cost-benefit analysis.

Powercor has not published generation constraints in the DAPR as the method for determining generation curtailment is still being assessed.

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[7] AEMO, Value of Customer Reliability Review Appendices, November 2014.

[8] AER, Values of Customer Reliability, Final Report on VCR Values, December 2019.

[9] AEMC, Rule Determination, National Electricity Amendment (Access, Pricing and Incentive Arrangements for Distributed Energy Resources) Rule 2021, 12 August 2021.

[10] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure-guidance-note/final-decision

7 Zone Substations Review

This chapter reviews the zone substations where further investigation into the balance between capacity, demand and REFCL compliance over the next five years is warranted, taking into account the:

- Import limitations:
  - forecasts for maximum demand to 2028
  - summer and winter cyclic N-1 import ratings for each zone substation
- Export limitations:
  - forecasts for minimum demand to 2028
  - cyclic N-1 export ratings for each zone substation
- REFCL compliance limitations:
  - compliance constraints forecasts to 2028

Where the zone substations are forecast to operate with maximum or minimum demands beyond 5 per cent of their firm summer or winter import or export rating during 2024 respectively, then this section assesses the energy at risk for those assets.

If the energy at risk assessment is material, then Powercor sets out possible options to address the system limitations. Powercor may employ the use of contingency load transfers to mitigate the system limitations although this will not always address the entire energy at risk at times of maximum demand. At other times of lower load, the available transfers may be greater. As a result, the use of load transfers under contingency situations may imply a short interruption of supply for customers or embedded generators to protect network elements from damage and enable all available load transfers to take place.

Non-network providers may wish to review the limitations and consider whether alternative solutions to those set out in the analysis may be suitable. Solutions may also address sub-transmission limitations at the same time. The annualised cost of the preferred network option provides a broad indication of the maximum potential value available to proponents of non-network solutions in deferring or avoiding network augmentation. However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation.

Powercor notes that all other zone substations that are not specifically mentioned below either have loadings below the relevant rating or the loading above the relevant rating is minimal and can be addressed using load transfer capability via the distribution network to adjacent zone substations. In these cases, all customers can be supplied following the failure or outage of an individual network element.

Finally, zone substations that are proposed to be commissioned during the forward planning period are also discussed and well as those which have forecast REFCL compliance constraints.

7.1 Zone substations with forecast system limitations overview

Based on the analysis presented in section 7.2 below, Powercor proposes to augment the zone substations with import limitations listed in the following table to address system limitations during the forward planning period. Powercor will investigate combining augmentation and asset replacement projects where it is cost effective to do so.

Table 7.7.1 Proposed import-limited zone substation augmentations

Zone substation	Description	Direct cost estimate ($ millions)				
		2024	2025	2026	2027	2028
BMH	BMH ZSS new transformer, circuit breakers, 66kV/22kV works and control room	0.15	0.33	2.5	3.5	0.7
DDL	Install a new 22kV GLE feeder and transfer load from DDL to GLE.					3.3
EHK	New transformer and REFCL			3.5	8.0	
MTC LV MLN WBE	Commission a new zone substation at Mount Cottrell (MTC) with three transformers	14	3.7			0.5

Powercor proposes to augment the zone substations with export limitations listed in the following table during the forward planning period.

Table 7.2 Proposed export-limited zone substation augmentations

Zone substation	Description	Direct cost estimate ($ million)				
		2024	2025	2026	2027	2028
Nil	-	-	-	-	-	-

Whist there are currently no identified export limitations, it should be noted that the export ratings currently used are thermal ratings only. Export ratings to accommodate reverse power flow should be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the thermal rating. Work is underway to quantify the impacts of system limitations on export ratings. Until that work is finalised, thermal ratings are applied.

Powercor is currently investigating a range of options in readiness for the expectation of future export limitations at our zone substations including:

- Reducing float voltages, or applying LDC settings at zone substations;
- Installing reactors at zone substations;
- Network reconfigurations and augmentations;
- Reviewing zone substation power transformer tap changer specification;
- Optimising existing capacitor bank switching settings at zone substations; and
- Non-network options.

In 2022 we introduced a Dynamic Voltage Management System to better manage export limitations associated with voltage. Powercor will continue to monitor the declining minimum demand levels on some of our zone substations and explore the feasibility of specific options to alleviate forecast export limitations on a case-by-case basis.

Powercor proposes to augment the zone substations with REFCL compliance limitations listed in the following table during the forward planning period.

Table 7.3 Proposed compliance-limited zone substation augmentations

Zone substation	Description	Direct cost estimate ($ million)				
		2024	2025	2026	2027	2028
ART	New isolating substation			0.5		
BAE	New REFCL Zone Substation, subtransmission lines and HV feeders	10.5	18.0	0.3		
BAE	New transformer, REFCL and HV feeders			0.7	11.8	0.7
BETS	Feeder rearrangement				0.5	2.4
CLC	New isolating substation with REFCL	1.0	7.0			
CLC	New isolating substation with REFCL				1.0	7.0
GHP	Feeder rearrangement				0.6	2.7

WND	New REFCL		1.8	4.5	2.7	

The excel based detailed system limitation reports can be found at the link below by searching for zone substation system limitation report:

https://spaces.hightail.com/space/UaPnYI6yeV

The options and analysis are explained below.

7.2 Zone substations with forecast system limitations

7.2.1 Ararat (ART) zone substation REFCL

The zone substation in Ararat (**ART**) is served by sub-transmission lines predominately from the Ballarat terminal station (BATS). It supplies the Ararat area.

Currently, the ART zone substation is comprised of two 10MVA transformers operating at 66/22kV, and has one REFCL.

Powercor estimates that a REFCL constraint is forecast at ART by 2027 due to increasing charging current and network damping from future customer developments. To address the anticipated system constraint at ART zone substation, Powercor considers that the following network solutions could be implemented to manage REFCL compliance risk:

- install a new isolating substation on an ART 22kV feeder for an estimated cost of $0.4 million
- install a new REFCL at ART for an estimated cost of $3.0 million.

Powercor's preferred option is to install a new isolating substation on an ART 22kV feeder in 2026 to maintain Powercor's REFCL compliance requirements.

7.2.2 Ballarat North (BAN) zone substation REFCL

The Ballarat North (**BAN**) zone substation is served by sub-transmission lines from the Ballarat terminal station (**BATS**). It supplies the area of Ballarat and extends into the surrounding northern and eastern areas of Clunes, Creswick and Daylesford.

Currently, the BAN zone substation is comprised of three 20/40MVA transformers operating at 66/22kV, and has three REFCLs.

Powercor estimates that a REFCL constaint is forecast at BAN by 2026 due to increasing charging current and network damping from future customer developments. To address both the anticipated system constraints at the BAN and BAS zone substations, Powercor considers that the following network solutions could be implemented to manage REFCL compliance risk:

- install a new Ballarat zone substation at Ballarat East (BAE) with two REFCLs for an estimated cost of $44.8 million
- install isolating substations with REFCLs on BAN/BAS 22kV feeders for an estimated cost of $36.7 million

- installing a new 25/33MVA fourth transformer and REFCL, and complete associated station work at BAS, and establish a new single transformer zone substation in Ballarat for an estimated cost of $59.4 million.

Powercor's preferred option is to install a new Ballarat zone substation in 2025 to maintain Powercor's REFCL compliance requirements and realise customer reliability and operational benefits compared to the least cost option.

7.2.3 Ballarat South (BAS) zone substation REFCL

The Ballarat South (**BAS**) zone substation is served by sub-transmission lines from the Ballarat terminal station (**BATS**). It supplies the area of Ballarat and extends into the surrounding southern and western areas of Buninyong, Beaufort, Smythesdale and Skipton.

Currently, the BAS zone substation is comprised of two 20/27/33MVA transformers and one 25/33 MVA transformer operating at 66/22kV, and has three REFCLs.

Powercor estimates that a REFCL constaint is forecast at BAS by 2026 due to increasing charging current and network damping from future customer developments. To address both the anticipated system constraints at the BAN and BAS zone substations, Powercor considers that the following network solutions could be implemented to manage REFCL compliance risk:

- install a new Ballarat zone substation at Ballarat East (BAE) with two REFCLs for an estimated cost of $44.8 million
- install isolating substations with REFCLs on BAN/BAS 22kV feeders for an estimated cost of $36.7 million
- installing a new fourth transformer and REFCL at BAS, and complete associated station work, and establish a new single transformer zone substation in Ballarat for an estimated cost of $59.4 million.

Powercor's preferred option is to install a new Ballarat zone substation in 2025 to maintain Powercor's REFCL compliance requirements and realise customer reliability and operational benefits compared to the least cost option.

7.2.4 Bacchus Marsh (BMH) zone substation

The zone substation in Bacchus Marsh (**BMH**) is served by two sub-transmission lines from the Brooklyn terminal station (**BLTS**) and Ballarat terminal station (**BATS**). This station supplies the domestic, commercial, industrial and farming areas of Bacchus Marsh, Balliang and surrounding areas along the Western Freeway.

Currently, the BMH zone substation is comprised of two 10/13.5MVA transformers operating at 66/22kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2027 there will be 13.58 MVA of load at risk and for 793 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at BMH. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at BMH zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Melton (MLN) and Ballarat North (BAN) up to a maximum transfer capacity of 2.7MVA

- install a new 25/33MVA third transformer and complete associated station work at BMH zone substation for an estimated cost of $7.4 million.

Powercor's preferred option is to install a new transformer in 2027. Although the expected demand will exceed the station's N-1 rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

A demand side initiative to reduce the forecast maximum demand load by 13.58 MW at this zone substation would defer the need for this capital investment by one year to 2028.

7.2.5 Bendigo (BETS) terminal station REFCL

The terminal station at Bendigo (**BETS**) contains a supply to the distribution network via eight 22kV distribution feeders. It supplies the City of Bendigo and the rural area to the south.

Currently, the BETS terminal station is comprised of two 55/75MVA transformers operating at 220/22kV, and has two REFCLs.

Powercor estimates that a REFCL constaint is forecast at BETS by 2029 due to increasing charging current and network damping from future customer developments. To address the anticipated system constraints at the BETS terminal station, Powercor considers that the following network solutions could be implemented to manage REFCL compliance risk:

- complete feeder reconfigurations for an estimated cost of $2.9 million
- install isolating substations for an estimated cost of $4.8 million

Powercor's preferred option is to complete feeder reconfigurations in 2028 to maintain Powercor's REFCL compliance requirements.

7.2.6 Bendigo (BGO) zone substation

The zone substation in Bendigo (**BGO**) is served by sub-transmission lines from the Bendigo terminal station (**BETS**). It supplies the City of Bendigo and the rural area to the east.

Currently, the BGO zone substation is comprised of two 20/27/33MVA transformers operating at 66/22kV and has two REFCLs. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 there will be 3.93 MVA of load at risk and for 12 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at BGO. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at BGO zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Eaglehawk (**EHK**) and BETS 22kV up to a maximum capacity of 13MVA
- install a new 25/33MVA third transformer at BGO zone substation for an estimated cost of $12.0 million.

Powercor's preferred option is to establish a new transformer at BGO. However, given that the forecast annual hours at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.2.7 Colac (CLC) zone substation REFCL

The zone substation in Colac (**BGO**) is served by sub-transmission lines from the Geelong terminal station (**GTS**) and Terang terminal station (**TGTS**). It supplies the Colac township and surrounding area, and reaches to the north and south including the coastal townships of Apollo Bay and Lorne.

Currently, the CLC zone substation is comprised of two 25/33MVA transformers and one 10/13.5MVA transformer operating at 66/22kV, and has three REFCLs.

Powercor estimates that a REFCL constaint is forecast at CLC by 2026 on the No.2 bus and by 2029 on the No.1 bus due to increasing charging current and network damping from future customer developments. To address the anticipated system constraints at the CLC zone substation, Powercor considers that the following network solutions could be implemented to manage REFCL compliance risk:

- install isolating substations with a REFCLs for an estimated cost of $16.0 million
- install a new Colac zone substation with a REFCL for an estimated cost of $35.0 million

Powercor's preferred option is to install isolating substations with a REFCLs in 2025 and 2028 to maintain Powercor's REFCL compliance requirements.

7.2.8 Cobram East (CME) zone substation

The zone substation in Cobram East (**CME**) is served by a sub-transmission line from the Numurkah zone substation (**NKA**). It supplies the domestic and commercial area of Cobram and Yarrawonga, extending into surrounding rural areas.

Currently, the CME zone substation is comprised of three 10/13.5 MVA transformers operating at 66/22 kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 there will be 4.59 MVA of load at risk and for 31 hours it would not be able to supply all customers from the zone substation if there is a failure of a transformer at CME. That is, it would not be able to supply all customers during high load periods following the loss of a 10/13.5 MVA transformer.

To address the anticipated system constraint at substation CME, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- Contingency plan to shed load and install portable emergency generation
- Augment capacity by replacing two 10/13.5 MVA transformers, each with a 25/33 MVA transformer, at an estimated cost of $7 million.

Powercor's preferred option is to augment capacity at CME by replacing two 10/13.5 MVA transformers, each with a 25/33 MVA transformer. However, given that the probability weighted value of energy at risk is not sufficient to justify augmentation, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N−1 cyclic rating, the use of load shedding and portable emergency generation will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.2.9 Cobden (COB) zone substation

Cobden Zone Substation (COB) 22 kV comprises of one 10/16 MVA 66/22kV transformer and one 10/13 MVA transformer supplying the 22 kV buses. COB supplies farming and gas production customers in the areas south of Cobden and dairy load in the Simpson area.Powercor estimates that in 2029 there will be 0.86 MVA of load at risk for less than 1 hour of the year it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at COB. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the COB substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Terang (TRG) and Camperdown (CDN) up to a maximum transfer capacity of 0.8 MVA
- augment capacity by installing an additional 66/22kV transformer and 22kV bus at COB, for an estimated cost of $8 million.

Powercor's preferred option is to construct a new transformer however this is not justified in the forward planning period and given the reducing forecast may never be justified. Although the expected demand will exceed the station's N-1 rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.10 Drysdale (DDL) Zone Substation

The zone substation in Drysdale (**DDL**) is served by sub-transmission lines from Geelong terminal station (**GTS**). It supplies the Bellarine Peninsula and coastal towns of Queenscliff, Point Lonsdale, Ocean Grove and Barwon Heads.

Currently, the DDL zone substation is comprised of two 20/27/33MVA transformers operating at 66/22kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 there will be 39.1 MVA of load at risk for 1,496 hours of the year it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at DDL. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the DDL substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

contingency plan to transfer load away via 22kV links to adjacent zone substations of Geelong East (**GLE**) and Waurn Ponds (**WPD**) up to a maximum transfer capacity of 10.6MVA

permanently transfer load away from DDL to GLE by constructing a new feeder at GLE for an estimated cost of $3.3 million.

augment capacity by installing an additional 66/22kV transformer and 22kV bus at DDL, for an estimated cost of $8.0 million.

Powercor's preferred option is to permanently transfer load away from DDL to GLE by constructing a new feeder at GLE ZSS in 2028. Therefore, a demand side initiative to reduce the forecast maximum demand load by 39.1MVA at this zone substation would defer the need for this capital investment by one year to 2028.

7.2.11 Eaglehawk (EHK) zone substation REFCL

The zone substation in Eaglehawk (**EHK**) is served by sub-transmission lines from the Bendigo terminal station (**BETS**). It supplies Eaglehawk, Bridgewater, Inglewood, the northern part of Bendigo and the surrounding rural areas north of Bendigo.

Currently, the EHK zone substation is comprised of two 20/27MVA transformers operating at 66/22kV and has two REFCLs. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 there will be 14.5 MVA of load at risk and for 167 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at EHK. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at EHK zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Bendigo zone substation (**BGO**) and Bendigo terminal station 22kV (**BETS 22kV**) up to a maximum transfer capacity of 22.4 MVA
- install a new 25/33MVA third transformer and REFCL at EHK, and complete associated station work for an estimated cost of $11.5 million.

It is expected that it will be most efficient to install the new transformer at the same time as the next REFCL at EHK as the third REFCL will require the installation of the new transformer. The total value of installing the REFCL and transformer is an estimated cost of $11.5 million.

Powercor's preferred option is to install a new transformer and REFCL at EHK in 2027. It is not expected that a demand management solution could defer this project due to the constraint imposed being related to charging currents and network damping. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.2.12 Geelong City (GCY) zone substation

The zone substation in Geelong City (**GCY**) is served by two sub-transmission lines from the Geelong terminal station (**GTS**). It supplies the domestic and commercial area of Geelong central business district and surrounding east and southern suburban areas.

Currently, the GCY zone substation is comprised of two 20/27/33MVA transformers operating at 66/22kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 there will be 10.5 MVA of load at risk for 75 hours of the year where it would be unable to supply all customers from the zone substation if there is a failure of one of the transformers at GCY. That is, it would be unable to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the GCY substation, Powercor considers that the following network solution could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Geelong (**GL**), Geelong East (**GLE**) and Waurn Ponds (**WPD**) up to a maximum transfer capacity of 16.4 MVA

Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period.

7.2.13 Gheringhap (GHP) zone substation REFCL

The zone substation in Gheringhap (**GHP**) is served by sub-transmission lines from the Geelong terminal station (**GTS**). It supplies the western outskirts of Geelong and surrounding areas, including Anakie, Bannockburn, Meredith and Shelford.

Currently, the GHP zone substation is comprised of two 25/33MVA transformers operating at 66/22kV, and has two REFCLs.

Powercor estimates that a REFCL constaint is forecast at GHP by 2029 due to increasing charging current and network damping from future customer developments. To address the anticipated system constraint at GHP zone substation, Powercor considers that the following network solutions could be implemented to manage REFCL compliance risk:

- complete feeder reconfigurations for an estimated cost of $3.3 million.
- installing a new 25/33MVA third transformer and REFCL, and complete associated station work at GHP for an estimated cost of $11.3 million.

Powercor's preferred option is to complete feeder reconfigurations in 2028 to maintain Powercor's REFCL compliance requirements.

7.2.14 Horsham (HSM) zone substation

The zone substation in Horsham (**HSM**) is served by sub-transmission lines from Horsham terminal station (**HOTS**). It supplies the city of Horsham and surrounding townships of Dimboola, Warracknabeal, Minyip, Murtoa and parts of the northern Grampians.

Currently, the HSM zone substation is comprised of three 10/13.5MVA transformers operating at 66/22kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 there will be 4.1 MVA of load at risk for 8.5 hours of the year where it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at HSM. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the HSM substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- Contingency plan to transfer load away via 22kV links to adjacent zone substations of Charam (CHM), Stawell (STL) and Nhill (NHL) up to a maximum transfer capacity of 3.1MVA
- Augment capacity by replacing two of the existing 10/13.5MVA transformers with 25/33MVA transformers at HSM at an estimated cost of $7 million.

Powercor's preferred option is to augment capacity by replacing two of the existing transformers with new 25/33MVA units at HSM. However, given that the probability weighted value of energy at risk is not sufficient to justify augmentation, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.2.15 Laverton (LV) zone substation

The Laverton (**LV**) zone substation is served by two sub-transmission lines from the Altona West terminal station (**ATS**). LV supplies the domestic and commercial area of Laverton extending into surrounding urban areas of Altona Meadows, Tarneit, Hoppers Crossing and Point Cook.

Currently, the LV zone substation is comprised of two 25/33MVA transformers and one 20/33MVA transformer operating at 66/22kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2025 there will be 19.9 MVA of load at risk and for 96.5 hours where it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at LV. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the LV zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to the adjacent zone substations of Laverton North (**LVN**) and Truganina (**TNA**) up to a maximum transfer capacity of 11.2 MVA in 2022/2023.
- build a new zone substation at Mount Cottrell (**MTC**) for a cost of $31m in 2025 and transfer load away from LV.

Powercor's preferred option is to build Mount Cottrell (**MTC**) zone substation in 2025 and transfer load away from LV. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

This project is driven by the overall load at risk at LV, WBE and TNA. Therefore, a demand side initiative to reduce the forecast maximum demand load by 50.32 MVA across these zone substations would defer the need for this capital investment by one year to 2026.

7.2.16 Laverton North (LVN) zone substation

The Laverton North (**LVN**) zone substation is served by two sub-transmission lines from the Altona West terminal station (**ATS**) and the Brooklyn terminal station (**BLTS**). Currently, the LVN zone substation is comprised of three 33MVA 66/22kV (referred to as LVN22 zone substation), as well as a single 20/30MVA 66/11kV transformer (referred to as LVN11 zone substation) supplying an industrial customer at high voltage (11kV).

Powercor estimates that in 2028 there will be 27 MVA of load at risk and for 402 hours where it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at LVN. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the LVN zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to the adjacent zone substations of Truganina (**TNA**) and Sunshine (**SU**) and Sunshine East (**SSE**) up to a maximum transfer capacity of 5 MVA in 2024.
- build a new transformer at LVN for a cost of $5m.

Powercor's preferred option is to build a new transformer at LVN in 2030. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.2.17 Merbein (MBN) zone substation

The zone substation in Merbein (**MBN**) is served from sub-transmission lines from Red Cliffs terminal station (**RCTS**). It supplies along the Murray River between Mildura and Lake Cullulleraine.

Currently, the MBN zone substation is comprised of two 10/13 MVA transformers and one 25/33MVA transformer operating at 66/22kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 there will be 12.95 MVA of load at risk and for 155 hours it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at MBN. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the MBN substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent Mildura zone substation (**MDA**) up to a maximum transfer capacity of 11.5 MVA
- augment capacity by replacing the No2 transformer with 25/33MVA for an estimated cost of $5.6 million.

Powercor's preferred option is to upgrade the No2 transformer with 25/33MVA transformer at MDA. However, given that the forecast annual hours at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the load at risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.2.18 Mildura (MDA) zone substation

The zone substation in Mildura (**MDA**) is served from sub-transmission lines from Red Cliffs terminal station (**RCTS**). It supplies the city of Mildura, the town of Irymple and a small irrigation area.

Currently, the MDA zone substation is comprised of two 20/33MVA transformers operating at 66/22kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 there will be 6.75 MVA of load at risk and for 27.5 hours it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at MDA. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the MDA substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent Merbein zone substation (**MBN**) and Red Cliffs terminal station (**RCTS 22kV**) up to a maximum transfer capacity of 15.9 MVA
- augment capacity by replacing the 25/33MVA transformer for an estimated cost of $5.6 million.

Powercor's preferred option is to install a new 25/33MVA transformer at MDA. However, given that the forecast annual hours at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the load at risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.2.19 Melton (MLN) zone substation

The zone substation in Melton (**MLN**) is served by two sub-transmission lines from the Deer Park terminal station (**DPTS**). MLN supplies the domestic and commercial area of Melton extending into surrounding urban areas of Mt Cottrell, Deer Park, Tarneit and Caroline Springs.

Melton Zone Substation (**MLN**) 22 kV comprises two 33 MVA 66/22kV transformers and one 25/33 MVA transformer supplying the 22 kV buses. The zone substation has a fully switched configuration, so that for a transformer fault, one transformer will be isolated, and the other will continue to supply the station load. MLN supplies the domestic, commercial and industrial area of Melton extending into surrounding rural areas.

Powercor estimates that in 2028 there will be 24.1 MVA of load at risk and for 88 hours it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at WBE. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the MLN substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to the adjacent zone substations of Sunshine East (**SSE**) and Truganina (**TNA**) up to a maximum transfer capacity of 5.7 MVA in 2022/23
- build a new zone substation at Mount Cottrell (**MTC**) for a cost of $31 million in 2025 and transfer load away from WBE.

Powercor's preferred option is to build Mount Cottrell (**MTC**) zone substation in 2025 and transfer load away. However, given that the forecast annual hours at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

This project is driven by the overall load at risk at LV, WBE and TNA. Therefore, a demand side initiative to reduce the forecast maximum demand load by 50.2 MVA in 2025 across these zone substations would defer the need for this capital investment by one year.

7.2.20 Mooroopna (MNA) zone substation

The zone substation in Mooroopna (**MNA**) is served by a sub-transmission line from the Shepparton terminal station (**SHTS**) and a Subtransmission line from Shepparton zone substation (**STN**). It supplies the domestic and commercial area of Mooroopna and Tatura, extending into surrounding rural areas.

Currently, the MNA zone substation is comprised of two 20/27/33 MVA transformers operating at 66/22 kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 there will be 3.6 MVA of load at risk and for 7.5 hours it would not be able to supply all customers from the zone substation if there is a failure of a transformer at MNA. That is, it would not be able to supply all customers during high load periods following the loss of a 20/27/33 MVA transformer.

To address the anticipated system constraint at substation MNA, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22 kV links to the adjacent zone substation of Shepparton (**STN**) up to a maximum transfer capacity of 8 MVA
- augment capacity by installing a third 25/33 MVA transformers, at an estimated cost of $5 million
- commission a new zone substation at Tatura (**TAT**) with two 25/33 MVA transformers and transfer load from MNA to TAT, at an estimated cost of $30 million.

Powercor's preferred option is to commission a new zone substation at Tatura (**TAT**) with two 25/33 MVA transformers. However, given that the probability weighted value of energy at risk is not sufficient to justify augmentation, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N−1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.2.21 Maryborough (MRO) zone substation

The zone substation in Maryborough (**MRO**) is served by sub-transmission lines from the Bendigo terminal station (**BETS**). It supplies Maryborough, Dunolly and the surrounding rural areas.

Currently, the MRO zone substation is comprised of two 10/13.5MVA transformers operating at 66/22kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 there will be 4.78 MVA of load at risk and for 112 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at MRO. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at MRO zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substation of Castlemaine (**CMN**) up to a maximum transfer capacity of 2.5MVA
- install a new 10/13.5MVA third transformer at MRO zone substation for an estimated cost of $5.5 million.

Powercor's preferred option is to establish a new transformer at MRO. However, given that the forecast annual hours at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.2.22 Stawell (STL) zone substation

The zone substation in Stawell (**STL**) is served by sub-transmission lines from Horsham terminal station (**HOTS**) and with an additional tie to Ballarat terminal station (**BATS**) via Ararat (**ART**) and Ballarat North (**BAN**) zone substations. It supplies the township of Stawell and the surrounding areas including parts of the north Grampians.

Currently, the STL zone substation is comprised of two 10/13.5MVA transformers operating at 66/22kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 there will be 3.17 MVA of load at risk for 36.5 hours of the year it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at STL. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the STL substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substation of Ararat (ART) up to a maximum transfer capacity of 3.5 MVA
- permanently transfer load away from STL to ART by constructing a new 20 km feeder at ART for an estimated cost of $4 million
- install a new 10/13.5MVA third transformer at STL zone substation for an estimated cost of $5 million.

Powercor's preferred option is to install a new transformer at STL. However, given that the forecast load at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.2.23 St Albans (SA) zone substation

The St. Albans (**SA**) zone substation is served by a looped sub-transmission line from the Keilor Terminal Station (**KTS**). It supplies the domestic and commercial areas of Keilor, Delahey, Taylors Hill, Sydenham, Caroline Springs and surroundings.

Currently, the SA zone substation is comprised of three 25/33MVA transformers operating at 66/22kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2025 there will be 7.9 MVA of load at risk and for 8 hours it will not be able to supply all customers from the zone substation if there is a failure of one of the transformers at SA. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at SA zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22 kV links to the adjacent Sunshine (**SU**) and Sunshine East (**SSE**) zone substation of up to a maximum transfer capacity of 9.3 MVA.
- Install new fans on the transformers to increase the rating of the zone substation.

Powercor's preferred option is to install new fans on the transformers at SA zone substation in 2024. Although the expected demand will exceed the station's N-1 rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.2.24 Terang (TRG) zone substation

The zone substation in Terang (**TRG**) is served by two sub-transmission lines from Terang terminal station (**TGTS**). It supplies Terang and surrounding rural area and is winter peaking.

Currently, the TRG zone substation is comprised of one 10/13.5MVA and one 25/33MVA transformer operating at 66/22kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 there will be 1.1 MVA of load at risk for 1 hours of the year where it would be unable to supply all customers from the zone substation if there is a failure of the larger transformer at TRG. That is, it would be unable to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the TRG zone substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Cobden (**COB**) and Camperdown (**CDN**) up to a maximum transfer capacity of 5.1MVA
- augment TRG by replacing the No.1 13.5MVA transformer with a larger 25/33MVA unit at an estimated cost of $4 million.

Powercor's preferred option is to augment TRG by replacing the No.1 13.5MVA transformer with a larger 25/33MVA unit. However, given that the forecast annual hours at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.2.25 Werribee (WBE) zone substation

The zone substation in Werribee (**WBE**) is served by two sub-transmission lines from the Altona West terminal station (**ATS**). WBE supplies the domestic and commercial area of Werribee extending into surrounding urban areas of Mt Cottrell, Wyndham Vale, Tarneit, Hoppers Crossing and Point Cook.

Currently, the WBE zone substation is comprised of two 20/33MVA and one 25/33MVA transformers operating at 66/22kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2025 there will be 30.42 MVA of load at risk and for 128.5 hours it would not be able to supply all customers from the zone substation if there is a failure of one of the transformers at WBE. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system constraint at the WBE substation, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to the adjacent zone substations of Laverton (**LV**) and Truganina (**TNA**) up to a maximum transfer capacity of 15.5 MVA in 2022/23
- build a new zone substation at Mount Cottrell (MTC) for a cost of $31m in 2025 and transfer load away from WBE.

Powercor's preferred option is to build Mount Cottrell (**MTC**) zone substation in 2025 and transfer load away. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

This project is driven by the overall load at risk at LV, WBE and TNA. Therefore, a demand side initiative to reduce the forecast maximum demand load by 50.2 MVA in 2025 across these zone substations would defer the need for this capital investment by one year.

7.2.26 Wemen (WMN) zone substation

The zone substation in Wemen (**WMN**) is served by a sub-transmission line from the Wemen terminal station (**WETS**). It supplies the domestic and commercial area of Wemen extending into surrounding rural areas.

Currently, the WMN zone substation is comprised of one 10/13.5MVA transformer and one 25/33MVA transformer operating at 66/22 kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 there will be 5.75 MVA of load at risk and for 105 hours it will not be able to supply all customers from the zone substation if there is a failure of 25/33 MVA transformers at WMN. That is, it would not be able to supply all customers during high load periods following the loss of the 25/33MVA transformer.

To address the anticipated system constraint at substation WMN, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to the adjacent zone substation of Robinvale (**RVL**) up to a maximum transfer capacity of 3.8 MVA
- augment capacity by replacing the 10/13.5MVA transformer with a 25/33MVA transformer at an estimated cost of $5 million.

Powercor's preferred option is to augment capacity at WMN by replacing the 10/13.5MVA transformer with a 25/33MVA transformer. However, given that the forecast annual hours at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

7.2.27 Woodend (WND) zone substation REFCL

The zone substation in Woodend (**WND**) is served by sub-transmission lines from the Keilor terminal station (**KTS**). It supplies the Woodend and surrounding areas, including Kyneton, Lancefield, Romsey and Trentham.

Currently, the WND zone substation is comprised of two 20/33MVA transformers operating at 66/22kV, and has two REFCLs.

Powercor estimates that a REFCL constaint is forecast at WND by 2027 due to increasing charging current and network damping from future customer developments. Powercor is also planning to conduct feeder rearrangements in 2023 at WND to manage REFCL compliance risks. To address the anticipated system constraint at WND zone substation, Powercor considers that the following network solutions could be implemented to manage REFCL compliance risk:

- install a new REFCL and switchboard at GSB, and transfer sections of WND via 22kV links for an estimated cost of $9.0 million.

- installing a new 25/33MVA third transformer and REFCL, and complete associated station work at WND for an estimated cost of $11.3 million.

Powercor's preferred option is to install a new REFCL and switchboard at GSB, and transfer sections of WND via 22kV links in 2026 to maintain Powercor's REFCL compliance requirements.

7.3 Proposed new zone substations

This section sets out Powercor's plans for new zone substations. These substations are not taken into account in the forecasts that have been referred to in the Forecast Maximum and Minimum Demand Sheet or in the analysis in section 7.1 above which relates to existing substations.

In summary, Powercor has committed to building the zone substation set out below in Table 7.4 during the forward planning period.

Table 7.4 Proposed new or redeveloped zone substations

Name	Location	Proposed commissioning date	Reason
Point Cook (PCK)	Metro South	2030	To facilitate demand growth in the area.
Rockbank East (RBE)	Metro North	2030	To facilitate demand growth in the area.
Ballarat East (BAE)	Ballarat	2025	To provide another REFCL support to support the growth in the area

7.3.1 Point Cook zone substation (PCK)

Powercor is planning to develop a new zone substation at Point Cook **(PCK)**, located in the Powercor Metro South area and to be supplied from ATS west. The new zone substation is commissioned to support the residential and commercial growth in the area by 2030.

7.3.2 Rockbank East zone substation (RBE)

Powercor is planning to develop a new zone substation at Rockbank East **(RBE)**, located in the Powercor Metro North area and to be supplied from DPTS. The new zone substation is commissioned to support the residential, commercial and industrial in Rockbank, Deanside, Mt. Atkinsons, Tarneit, Eynesbury, Manor Lakes and surrounding areas by 2030.

7.3.3 Ballarat East zone substation (BAE)

A new zone substation in the Ballarat area is proposed to commence option analysis, scope concept and design in 2023 and 2024. The new zone substation is to be commissioned to provide another REFCL to support the growth in the Ballarat area that is causing increases in charging current and network damping leading to REFCL compliance being at risk.

8 Sub-transmission Lines Review

This chapter reviews the sub-transmission lines where further investigation into the balance between capacity and demand over the next five years is warranted, taking into account the:

- Import limitations:
  - forecasts for N-1 maximum demand to 2028
  - line import ratings for each subtransmission line
- Export limitations:
  - forecasts for N-1 minimum demand to 2028
  - line export ratings for each sub-transmission line

Where the sub-transmission line is forecast to operate with maximum or minimum demands beyond 10 per cent of their summer or winter import or export rating (respectively) under N-1 conditions during 2023, this chapter assesses the energy at risk for those assets.

If the energy at risk assessment is material, then Powercor sets out possible options to address the system limitations. Powercor may employ the use of contingency load transfers to mitigate the system limitations although this will not always address the entire energy at risk at times of maximum demand. At other times of lower load the available transfers may be greater. As a result, the use of load transfers under contingency situations may imply a short interruption of supply for customers or embedded generators to protect network elements from damage and enable all available load transfers to take place.

Non-network providers may wish to review the limitations and consider whether alternative solutions to those set out in the analysis may be suitable. Solutions may also address zone substation limitations at the same time. The annualised cost of the preferred network option provides a broad indication of the maximum potential value available to proponents of non-network solutions in deferring or avoiding network augmentation. However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation.

Powercor notes that all other sub-transmission lines that are not specifically mentioned below either have loadings below the relevant rating or the loading above the relevant rating is minimal and can be addressed using the load transfer capability. In these cases, all customers can be supplied following the failure or outage of an individual network element.

Finally, sub-transmission lines that are proposed to be commissioned during the forward planning period are also discussed.

8.1 Sub-transmission lines with forecast system limitations overview

Using the analysis undertaken below in section 8.2, Powercor proposes to augment the sub-transmission lines with import limitations listed in the table below to address system limitations during the forward planning period. For completeness, sub-transmission lines with forecast import limitations with no proposed expenditure are also listed.

Table 8.1 Proposed import-limited sub-transmission line augmentations

Sub-transmission line	Description	Direct cost estimate ($ million)				
		2024	2025	2026	2027	2028
ATS-WBE-HCP	Load at risk is forecasted for these sub-transmission lines but will be managed without proposing sub-transmission line augmentation	-	-	-	-	-
BATS-YSW-BGL		-	-	-	-	-
BETS-BGO-EHK		-	-	-	-	-
GTS-GB-GL-GCY		-	-	-	-	-
GTS-GLE-DDL		-	-	-	-	-
KGTS-GSF-SHL		-	-	-	-	-
RCTS-MDA-MBN		-	-	-	-	-

Powercor proposes to augment sub-tranmission lines with export limitations listed in the table below during the forward planning period. For completeness, sub-transmission lines with forecast export limitations with no proposed expenditure are also listed.

Table 8.2 Proposed export-limited sub-transmission line augmentations

Sub-transmission line	Description	Direct cost estimate ($ million)				
		2023	2024	2025	2026	2027
BAN-BGR	Large sub-transmission connected generators are forecast to be exposed to more frequent, increased levels of runback curtailment under N-1 conditions, due to declining minimum demand and uptake of rooftop solar PV, within the localised distribution networks.	-	-	-	-	-
GTS-WIN		-	-	-	-	-
WIN-MGW		-	-	-	-	-
KGTS-GSF		-	-	-	-	-
RCTS-KSF		-	-	-	-	-
SHTS-NSF		-	-	-	-	-
TGTS-HTN		-	-	-	-	-
NRB-HTN		-	-	-	-	-
TGTS-NRB		-	-	-	-	-
WETS-WSF		-	-	-	-	-
WETS-BSP		-	-	-	-	-

It should be noted that the export ratings currently used are thermal ratings only. Export ratings to accommodate reverse power flow should be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the thermal rating. Work is underway to quantify the impacts of system limitations on export ratings. Until that work is finalised, thermal ratings are applied.

Whilst there is currently no proposed expenditure to address our sub-transmission line export limitations, Powercor is currently investigating a range of options in readiness for the expectation of future RIT-Ds to address the export limitations on our sub-transmission lines. Options could include:

- reducing float voltages, or applying LDC settings at terminal stations
- installing reactors at terminal stations
- network reconfigurations and augmentations
- reviewing terminal station power transformer tap changer specification
- optimising existing capacitor bank switching controls at terminal stations
- non-network options.

In the interim, the export limitations are being managed by runback and curtailment of the sub-transmission connected generators. The identified sub-transmission lines with export limitations are discussed in more detail in section 8.2 below. Powercor will continue to monitor the declining minimum demand levels on our other sub-transmission lines and explore the feasibility of specific options to alleviate forecast export limitations on a case-by-case basis.

The excel based detailed system limitation reports for the substransmission lines with forecast limitations can be found at the link below by searching for sub-transmission system limitation report:

https://spaces.hightail.com/space/UaPnYI6yeV

The options and analysis are explained in the sections below.

8.2 Sub-transmission lines with forecast system limitations

8.2.1 ATS-HCP-WBE-ATS 66 kV sub-transmission loop

The ATS-WBE-HCP sub-transmission loop supplies the Werribee (**WBE**) and Hoppers Crossing (**HCP**) zone substations fed from Altona terminal station (**ATS**) at 66 kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 for the lines within this loop there will be:

- 53.2 MVA of load at risk and for 52 hours it will not be able to supply all customers from the ATS-HCP line if there is an outage of the ATS-WBE sub-transmission line
- 55.3 MVA of load at risk and for 55 hours it will not be able to supply all customers from the ATS-WBE line if there is an outage of the ATS-HCP sub-transmission line.

To address the anticipated system constraints within this sub-transmission loop, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22 kV links to the adjacent zone substation of Laverton (**LV**) up to a maximum transfer capacity of 13.6 MVA
- contingency plan to transfer load away via 22 kV links to the adjacent zone substation of Truganina (**TNA**) up to a maximum transfer capacity of 15.7 MVA
- augment transfers away capacity from WBE to TNA by establishing more feeder ties, since TNA has had a third transformer installed and is able to manage more permanent transfers as well as contingency transfers.

Powercor's preferred option is to augment the transfers away capacity from WBE to TNA. However, given that the forecast annual hours at risk is low there is no project expected to occur during the forecast period. Although the expected demand will exceed the sub-transmission line's N-1 cyclic rating for worst case scenario, the use of contingency load transfers will mitigate the risk in the interim period.

8.2.2 BATS-YSW/BGL 66 kV sub-transmission line

The BATS-YSW/BGL sub-transmission line forms part of the BATS-BGL-YSW-BMH-BLTS sub-tranmission tie between Ballarat terminal station (**BATS**) and Brooklyn terminal station (**BLTS**) at 66 kV through Bacchus Marsh (**BMH**). For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 for the lines within this loop there will be 72.1 MVA of load at risk, and for 9 hours it would not be able to supply all customers on the BATS-BGL-YSW-BMH-BLTS line during an outage of the BATS-BLTS line.

To address the anticipated system constraints within this sub-transmission loop, Powercor proposes to manage the load at risk through its contingency plan to transfer load away via Bacchus Marsh (**BMH**) zone substation.

To protect the line from damage, Powercor has an automatic line protection scheme in service. Although the expected demand will exceed the sub-transmission line N-1 rating, for worst case outage, the use of contingency load transfers will mitigate the risk in the interim period.

8.2.3 BETS-BGO-EHK-BETS 66 kV sub-transmission loop

The BETS-BGO-EHK sub-transmission loop supplies the Bendigo (**BGO**) and Eaglehawk (**EHK**) zone substations that fed from Bendigo terminal station (**BETS**) at 66 kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 for the lines within this loop there will be 19.2 MVA of load at risk, and for 3 hours it would not be able to supply all customers on the BETS-BGO-EHK line during an outage of the BETS-EHK line.

To address the anticipated system constraints within this sub-transmission loop, Powercor proposes to manage the load at risk through its contingency plan to transfer load away via 22 kV links to the adjacent Bendigo terminal station 22kV (**BETS22)** for up to a maximum transfer capacity of 20 MVA.

To protect the line from damage, Powercor has an automatic line protection scheme in service. Although the expected demand will exceed the sub-transmission line N-1 rating, for worst case outage, the use of contingency load transfers will mitigate the risk in the interim period.

8.2.4 GTS-GB-GL-GCY 66 kV sub-transmission loop

The GTS-GB-GL-GCY 66kV sub-transmission loop supplies the Geelong City (**GCY**), Geelong B (**GB**) and Geelong (**GL**) zone substations fed from Geelong terminal station (**GTS**) at 66 kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 for the lines within this loop there will be:

- 44.4 MVA of load at risk and for 36 hours it will not be able to supply all customers from the GTS-GCY line if there is an outage of the GTS-GB sub-transmission line
- 1.8 MVA of load at risk and for 1 hours it will not be able to supply all customers from the GB-GL line if there is an outage of the GTS-GCY sub-transmission line.

To address the anticipated system constraints within this sub-transmission loop, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22 kV links to the adjacent zone substation of Waurn Ponds (**WPD**) and Geelong East (**GLE**) up to a maximum transfer capacity of 18.4 MVA
- utilise limited cyclic ratings to alleviate the load at risk under contingency conditions.

The forecast annual hours at risk is low and GL is planned to be offloaded in 2023 to new Gheringhap (GHP) zone substation. Powercor also has an automatic load shed scheme in service. Although the expected demand will exceed the sub-transmission line N-1 rating, for worst case outage, the use of limited cyclic ratings and contingency load transfers will mitigate the risk in the interim period.

8.2.5 GTS-GLE-DDL 66 kV sub-transmission loop

The GTS-GLE-DDL sub-transmission loop supplies the Geelong East (**GLE**) and Drysdale (**DDL**) zone substations fed from Geelong terminal station (**GTS**) at 66 kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 for the lines within this loop there will be:

- 61.4 MVA of load at risk and for 24 hours it would not be able to supply all customers from the GTS-GLE2 line if there is an outage of the GTS-GLE1 sub-transmission line
- 44.1 MVA of load at risk and for 13 hours it would not be able to supply all customers from the GTS-GLE1 line if there is an outage of the GTS-GLE2 sub-transmission line.

To address the anticipated system constraints within this sub-transmission loop, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22 kV links to adjacent zone substations
- upgrade GTS-GLE1 and GTS-GLE2 lines at a cost of $1,500,000 each.

Given that the forecast annual hours at risk is low there is no project expected to occur during the forecast period. To protect the line from damage, Powercor has an automatic load shed scheme in service. Although the expected demand will exceed the sub-transmission line N-1 rating, for worst case outage, the use of limited cyclic ratings and contingency load transfers will mitigate the risk in the interim period.

8.2.6 KGTS-SHL 66 kV sub-transmission loop

The KGTS-GSF-SHL sub-transmission loop supplies the Gannawarra Solar Farm (GSF) and Swan Hill (SHL) zone substation from Kerang terminal station (KGTS) at 66kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the Forecast Maximum and Minimum Demand Sheet.

Powercor estimates that in 2028 for the lines within this loop there will be 28.7 MVA of load at risk and for 194 hours it will not be able to supply all customers from the KGTS-SHL line if there is an outage of the KGTS-GSF or GSF-SHL sub-transmission lines due to 66kV line voltage limitations.

To address the anticipated system constraints within this sub-transmission loop, Powercor considers that the following network solutions could be implemented to manage the load at risk:

- contingency plan to transfer load away via 22kV links to the Boundary Bend (BBD) zone substation up to a maximum transfer capacity of 1 MVA
- contingency plan to transfer load away via 22kV links to the Kerang terminal station (KGTS 22kV) up to a maximum transfer capacity of 4.1 MVA
- augment the sub-transmission lines by replacing the small conductors with larger conductors in order to increase the voltage limitation on the KGTS-SHL line at an estimated cost of $13 million.

Powercor's preferred option is to replace the conductors on the KGTS-SHL line over the longer term, which would also address voltage and thermal rating constraints under N-1 conditions. However, given that the probability weighted value of energy at risk is not sufficient to justify augmentation, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N-1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period.

To protect the lines from damage, Powercor has installed an automatic line protection scheme.

8.2.7 RCTS-MDA-MBN 66 kV sub-transmission loop

The RCTS-MDA-MBN sub-transmission loop supplies the Mildura (**MDA**) and Merebin (**MBN**) zone substations fed from Red Cliffs terminal station (**RCTS**) at 66 kV. For the historical and forecast asset ratings and forecast station maximum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028 for the lines within this loop there will be 42 MVA of load at risk, and for 485 hours it would not be able to supply all customers on the RCTS-MDA1 line during an outage of the RCTS-MDA2 or MBN-MDA lines.

To address the anticipated system constraints within this sub-transmission loop, Powercor proposes to manage the load at risk through its contingency plan to transfer load away via 22 kV links to the adjacent Redcliff Terminal Station 22kV (**RCTS22**). The maximum transfer capacity is 12.2 MVA.

To protect the line from damage, Powercor has an automatic line protection scheme in service. Although the expected demand will exceed the sub-transmission line N-1 rating, for worst case outage, the use of contingency load transfers will mitigate the risk in the interim period.

8.2.8 BAN-BGR 66 kV sub-transmission line export limitation

The BAN-BGR 66kV sub-transmission line forms part of the BATS-BAN-BGR/CHW-ART-STL-HOTS sub-transmission tie between Ballarat terminal station (**BATS**) and Horsham terminal station (**HOTS**). For the export ratings and forecast minimum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028, for limitations on BAN-BGR there will be:

- 17.8 MVA of generation at risk of curtailment if there is an outage of the ART-BGR or STL-ART sub-transmission lines.

To address the export limitations on this sub-transmission line, Powercor considers that the following solutions could be implemented to manage the load at risk:

- Run-back generation at CHW (and potentially other sites) to manage the line loading under contingency conditions.

- Duplicate the sub-transmission line from BAN to BGR.

Powercor's preferred option is to maintain the run-back capability in the interim period until there is an economic case to augment the network through a future RIT-D process.

8.2.9 GTS-WIN and WIN-MGW 66 kV sub-transmission line export limitations

The GTS-WIN and WIN-MGW 66kV sub-transmission lines form part of the GTS-WIN-MGW-CLC-CDN/COB-TGTS sub-transmission tie between Geelong terminal station (**GTS**) and Terang terminal station (**TGTS**). For the export ratings and forecast minimum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028, there will be:

- for limitations on GTS-WIN, 62.8 MVA of generation at risk of curtailment if there is an outage of the CLC-MGW or CLC-CDN sub-transmission lines.
- for limitations on WIN-MGW, 26.3 MVA of generation at risk of curtailment if there is an outage of the CLC-MGW or CLC-CDN sub-transmission lines

To address the export limitations on these sub-transmission lines, Powercor considers that the following solutions could be implemented to manage the load at risk:

- Run-back generation at MGW (and potentially other sites) to manage the line loading under contingency conditions.
- Duplicate the sub-transmission line from GTS to WIN.
- Duplicate the sub-transmission line from WIN to MGW.
- Install a new sub-transmission line from GTS to MGW.

Powercor's preferred option is to maintain the run-back capability in the interim period until there is an economic case to augment the network through a future RIT-D process.

8.2.10 KGTS-GSF 66 kV sub-transmission line export limitation

The KGTS-GSF 66kV sub-transmission line forms part of the KGTS-GSF-SHL-KGTS sub-transmission loop at Kerang terminal station (**KGTS**). For the export ratings and forecast minimum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028, for limitations on KGTS-GSF there will be:

- 14.7 MVA of generation at risk of curtailment if there is an outage of the KGTS-SHL sub-transmission line.

To address the export limitations on this sub-transmission line, Powercor considers that the following solutions could be implemented to manage the load at risk:

- Run-back generation at GSF (and potentially other sites) to manage the line loading under contingency conditions.
- Duplicate the sub-transmission line from KGTS to GSF.

Powercor's preferred option is to maintain the run-back capability in the interim period until there is an economic case to augment the network through a future RIT-D process.

8.2.11 RCTS-KSF, WETS-WSF and WETS-BSP 66 kV sub-transmission line export limitations

The RCTS-KSF, WETS-WSF and WETS-BSP 66kV sub-transmission lines form part of the RCTS-KSF-RVL-BSP/BBD-WMN/WSF-WETS sub-transmission tie between Redcliffs terminal station (**RCTS**) and Wemen terminal station (**WETS**). For the export ratings and forecast minimum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028, there will be:

- for limitations on RCTS-KSF, 12.2 MVA of generation at risk of curtailment if there is an outage of the WETS-BSP or WETS-WSF sub-transmission line.
- for limitations on WETS-WSF, 3.6 MVA of generation at risk of curtailment if there is an outage of the RCTS-KSF sub-transmission line.
- for limitations on WETS-BSP, 8.9 MVA of generation at risk of curtailment if there is an outage of the RCTS-KSF sub-transmission line.

To address the export limitations on this sub-transmission line, Powercor considers that the following solutions could be implemented to manage the load at risk:

- Run-back generation at KSF, BSP or WSF (and potentially other sites) to manage the line loading under contingency conditions.
- Duplicate the sub-transmission line from RCTS to KSF.
- Duplicate the sub-transmission line from WETS to BSP.

Powercor's preferred option is to maintain the run-back capability in the interim period until there is an economic case to augment the network through a future RIT-D process.

8.2.12 SHTS-NSF 66 kV sub-transmission line export limitation

The SHTS-NSF 66kV sub-transmission line forms part of the SHTS-NSF-NKA/CME-SHTS sub-transmission loop at Shepparton terminal station (**SHTS**). For the export ratings and forecast minimum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028, for limitations on SHTS-NSF there will be:

- 30.9 MVA of generation at risk of curtailment if there is an outage of the SHTS-NKA sub-transmission line.

To address the export limitations on this sub-transmission line, Powercor considers that the following solutions could be implemented to manage the load at risk:

- Run-back generation at NSF (and potentially other sites) to manage the line loading under contingency conditions.
- Duplicate the sub-transmission line from SHTS to NSF.
- Install a new sub-transmission line from SHTS to CME.

Powercor's preferred option is to maintain the run-back capability in the interim period until there is an economic case to augment the network through a future RIT-D process.

8.2.13 TGTS-HTN, NRB-HTN and TGTS-NRB 66 kV sub-transmission line export limitations

The TGTS-HTN, NRB-HTN and TGTS-NRB 66kV sub-transmission lines form part of the TGTS-HTN-NRB/OWF/MLW-SHTS sub-transmission loop at Terang terminal station (**TGTS**). For the export ratings and forecast minimum demand, please refer to the System Limitations Template.

Powercor estimates that in 2028, there will be:

- for limitations on TGTS-HTN, 34.8 MVA of generation at risk of curtailment if there is an outage of the SHTS-NKA sub-transmission line.
- for limitations on NRB-HTN, 26.3 MVA of generation at risk of curtailment if there is an outage of the SHTS-NKA sub-transmission line.
- for limitations on TGTS-NRB, 29.1 MVA of generation at risk of curtailment if there is an outage of the SHTS-NKA sub-transmission line.

To address the export limitations on this sub-transmission line, Powercor considers that the following solutions could be implemented to manage the load at risk:

- Run-back generation at OWF and MLW (and potentially other sites) to manage the line loading under contingency conditions.
- Duplicate the sub-transmission line from TGTS to NRB.
- Reconductor NRB to HTS section of the loop.
- Reconductor all critical sections of the entire loop.

Powercor's preferred option is to maintain the run-back capability in the interim period until there is an economic case to augment the network through a future RIT-D process.

8.3 Proposed new sub-transmission lines

This section sets out Powercor's plans for new sub-transmission lines. These lines are taken into account in the forecasts that have been set out in the Forecast Maximum and Minimum Demand Sheet and the analysis in section 8.2 above which relates to existing sub-transmission lines.

In summary, Powercor plans to build the sub-transmission lines set out below in Table 8.3 during the forward planning period.

Table 8.3 new sub transmission lines

Sub transmission lines	Description	Proposed commissioning date
Mt Cottrell (MTC) two new 66kV lines	To supply the new MTC zone substation	2025

9 Transmission-Distribution Connection Point Review

This chapter reviews the terminal stations where further investigation into the balance between capacity and demand over the next five years is warranted, taking into account the:

- Import limitations:
  - These are addressed in the Transmission Connection Planning Report
- Export limitations:
  - forecasts for minimum demand to 2028
  - nameplate N and N-1 export ratings for each terminal station

Where the terminal stations are forecast to operate with minimum demands beyond 5 per cent of their firm export rating during 2024, then this section assesses the energy at risk for those assets.

If the energy at risk assessment is material, then Powercor sets out possible options to address the system limitations. Powercor may employ the use of contingency transfers to mitigate the system limitations although this will not always address the entire energy at risk. At other times the available transfers may be greater. As a result, the use of transfers under contingency situations may imply a short interruption of supply for customers or embedded generators to protect network elements from damage and enable all available transfers to take place.

Non-network providers may wish to review the limitations and consider whether alternative solutions to those set out in the analysis may be suitable. The annualised cost of the preferred network option provides a broad indication of the maximum potential value available to proponents of non-network solutions in deferring or avoiding network augmentation. However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation. Solutions may also address zone substation limitations at the same time.

Powercor notes that all other terminal stations that are not specifically mentioned below either have loadings below the relevant rating or the loading above the relevant rating is minimal and can be addressed using load transfer capability via the distribution and sub-transmission network to adjacent terminal stations. In these cases, all customers can be supplied following the failure or outage of an individual network element.

9.1 Terminal stations with forecast system limitations overview

Powercor has to date, not identified any terminal stations with export limitations.

Whist there are currently no identified limitations from the forecast use of distribution services by embedded generating units at transmission-distribution connection points, it should be noted that the export ratings currently used for terminal stations are thermal ratings only. Export ratings to accommodate reverse power flow should be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the terminal station's thermal rating. Work is underway to quantify the impacts of system limitations on terminal station export ratings. Until that work is finalised, thermal ratings are applied.

10 Primary Distribution Feeder Reviews

This chapter reviews the primary distribution feeders where further investigation into the balance between capacity and demand over the next two years is warranted, taking into account the:

- Import limitations:
  - forecasts for maximum demand to 2025
  - summer and winter cyclic import ratings for each feeder
- Export limitations:
  - forecasts for minimum demand to 2025
  - cyclic export ratings for each feeder

Where the feeders are forecast to operate with maximum or minimum demands in breach of their import or export rating (respectively) over the next two years, then this section assesses the energy at risk for those assets.

This review considers the primary section of a feeder, or what is commonly known as the backbone of the feeder exiting the zone substation to the first point of load for a low-voltage feeder or customer.

If the energy at risk assessment is material, then Powercor sets out possible options to address the system limitations. Powercor may employ the use of contingency load transfers to mitigate the system limitations although this will not always address the entire energy at risk at times of maximum demand. At other times of lower load the available transfers may be greater. As a result, the use of load transfers under contingency situations may imply a short interruption of supply for customers or embedded generators to protect network elements from damage and enable all available load transfers to take place.

Non-network providers may wish to review the limitations and consider whether alternative solutions to those set out in the analysis may be suitable. Solutions may also address distribution feeder limitations at the same time.

Finally, distribution feeders that are proposed to be commissioned during the next two years are also discussed.

10.1 Primary distribution feeders with forecast system limitations overview

Powercor proposes to augment the import-limited feeders listed in the table 10.1 below in the next two years.

Table 10.1 – Proposed import-limited primary distribution feeders augmentations

Feeder	Description	Direct cost estimate ($ million)	
		2023	2024
Nil	-	-	-

Powercor proposes to augment the export-limited feeders listed in Table 10.2 below in the next two years.

Table 10.2 – Proposed export-limited primary distribution feeders augmentations

Feeder	Description	Direct cost estimate ($ million)	
		2023	2024
Nil	-	-	-

The excel based detailed system limitation reports for the primary distribution feeders with forecast limitations can be found at the link below by searching for primary feeder system limitation report:

https://spaces.hightail.com/space/UaPnYI6yeV

10.2 Proposed new primary distribution feeders

Powercor proposes to construct the feeders listed in table 10.3 below in the next two years.

Table 10.3 – Proposed new primary distribution feeders

Feeder	Description	Direct cost estimate ($ million)	
		2024	2025
BAS031	Construction of new BAS031 feeder	1.89	

Feeder	Description	Direct cost estimate ($ million)	
		2024	2025
CMN008	Construction of new CMN008 feeder	0.13	

10.2.1 BAS031 feeder

The Ballarat South (BAS) zone substation supplies domestic, commercial and industrial areas in the Ballarat CBD, the southern suburbs of Ballarat such as Delacombe, Sebastopol and Buninyong, the western suburbs of Ballarat such as Alfredton and Lucas, the rural areas to the south of Ballarat such as Elaine and also the rural areas to the west of Ballarat such as Skipton and Beaufort. It comprises of two 20/27/33MVA transformers and one 25/33MVA transformer and nine 22kV feeders.

There is substantial ongoing residential development in the southern and western suburbs of Ballarat around Alfredton, Lucas and Delacombe.

Outside of the Ballarat suburban area the feeders to the west and south of Ballarat are radial and have no transfer options.

A new BAS031 feeder to Sebastopol will offload BAS022, BAS033 and BAS034 feeders and provide supply reliability in the event of a feeder fault.

Load on BAS033 feeder has already exceeded feeder summer N rating in previous summers. There is significant ongoing residential development at Delacombe, being supplied from BAS033 feeder and also BAS022 feeder.

Powercor estimates that on BAS033 feeder, in winter 2024, there will be 5.8 MVA of unserved load above the thermal rating for 1,222 hours during system normal conditions. Based on load forecasts and to address constraints the following network solutions have been considered:

- construct a new BAS031 feeder to Sebastopol at an estimated cost of $1.3 million
- augment feeder exits and backbones on BAS022, BAS033 & BAS034 feeders at an estimated cost of $2.4 million.

The construction of new BAS031 feeder is the preferred option as it is the least cost option that removes forecast overload on BAS033 feeder and also reduces load on BAS022 & BAS034 feeders and has been approved for commencement in 2023. A demand side initiative to reduce the forecast maximum demand load by 5.8 MW on BAS033 feeder would defer the need for this capital investment by one year in 2024. Please refer to the System Limitations Template for further information regarding the network investment after the project has been completed.

The ultimate augmentation plan to cater for ongoing load growth and to address constraints is to establish a new zone substation at Ballarat West, beyond 2026.

10.2.2 CMN008 feeder

The Castlemaine (CMN) zone substation supplies customers in the Castlemaine and surrounding area including Maldon, Malmsbury and Newstead. It comprises of two 25/33MVA transformers and five 22kV feeders.

The CMN001 feeder supplies the Malmsbury area has a large number of rural customers on it and reliability concerns. To address these constraints the following network solutions have been considered:

- construct a new CMN008 feeder to split CMN001 at an estimated cost of $0.8 million
- install a battery energy storage system (BESS) on CMN001 at an estimated cost of $6.0 million.

The construction of new CMN008 feeder is the preferred option as it is the least cost option that addresses the constraints and enables a future REFCL augmentation to be deferred by at least six years. It has been approved and is partially built with completion planned in 2024.

10.3 Future proposed new primary distribution feeder projects

The following primary distribution feeder projects are proposed to commence scope investigation and option analysis in 2024.

- GLE new feeder

11 Joint Planning

Powercor has not identified any new projects from our joint planning activities with other DNSPs in 2023. Our joint planning activities have included sharing load forecast information and load flow analysis between Victorian distributors relating to the sub-transmission system. Where a constraint is identified on our network that may impact another distributor, then project specific joint planning meetings are held to determine the most efficient and effective investment strategy to address the system constraint.

Joint planning in relation to terminal stations is discussed in the Transmission Connection Planning Report.

12 Changes to Analysis Since 2022

The following information details load forecasts and project timing changes that have occurred since the publication of the 2022 DAPR.

12.1 Constraints addressed or reduced due to projects completed

Powercor has undertaken the following projects in 2023 to address constraints identified in the 2022 DAPR:

- Geringhap (**GHP**) zone substation built and commissioning completed in 2023, resolving constraints at (**CRO**) and (**GL**) via transfers
- Torquay (**TQY**) zone substation built and commissioning completed in 2023, resolving constraints at (**WPD**) via transfers

12.2 New constraints identified

Changes in load forecasts or other factors during 2023 have resulted in Powercor undertaking risk assessments for the following zone substations or sub-transmission lines, which were not included in the 2022 DAPR:

- Cobram East (**CME**) zone substation load forecasts have increased, resulting in load and hours at risk above threshold limits
- Cobden (**COB**) zone substation load forecasts have increased, resulting in load and hours at risk above threshold limits
- Laverton North (**LVN**) zone substation load forecasts have increased, resulting in load and hours at risk above threshold limits
- Melton (**MLN**) zone substation load forecasts have increased, resulting in load and hours at risk above threshold limits
- Stawell (**STL**) zone substation load forecasts have increased, resulting in load and hours at risk above threshold limits

12.3 Other material changes

In addition to the matters identified above, material changes compared to the 2022 DAPR include:

- Nil

13 Asset Management

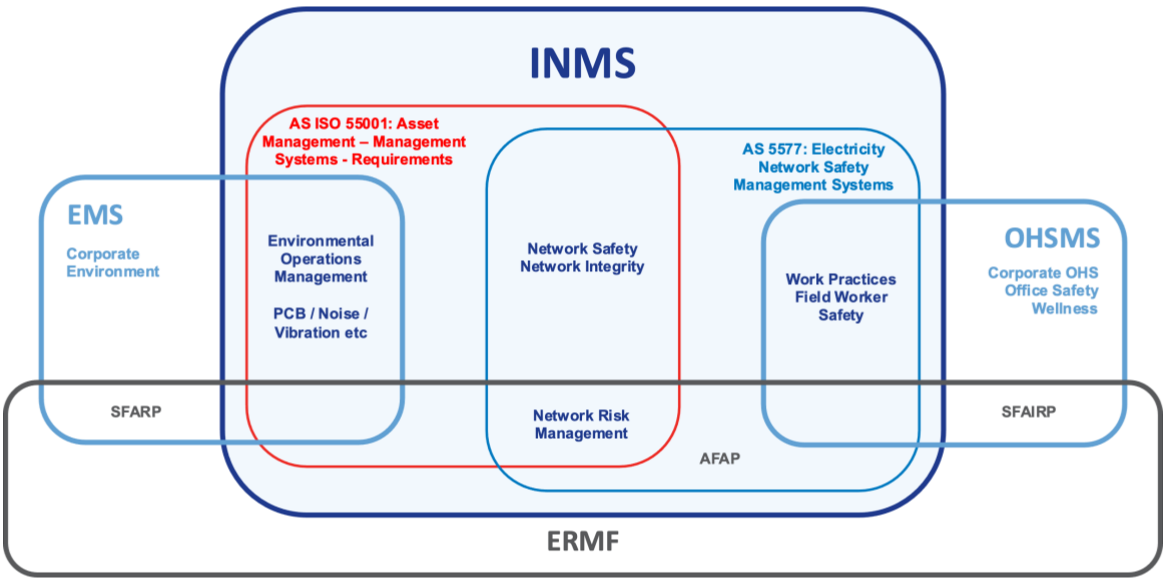
This chapter details the Powercor Asset Management System (**AMS**), that forms part of the Integrated Network Management system (**INMS**) and harmonises the requirements of the various management systems.

13.1 Integrated Network Management System (INMS)

The INMS integrates the requirements of four management systems, underpinned by the the Enterprise Risk Management Framework (**ERMF**). It articulates the integrated management system policies, strategies, plans, and procedures:

- Asset Management System (**AMS**),
- Electricity (Network) Safety Management System (**ESMS**),
- Occupational Health and Safety Management System (**OHSMS**),
- Environmental Management System (**EMS**).

Figure 13.1 Scope of the integrated network management system



The scope of the INMS, as defined in **Figure 13.1**, is limited to the electricity network and the associated operating environment and the requirements of the following two management system standards:

- AS ISO 55001:2014 Asset Management – Management Systems – Requirements
- AS 5577:2013 Electricity Network Safety Management Systems.

These management system standards are aligned with the following management system standards for which CPPAL already has certification:

- AS/NZS ISO 45001:2018 Occupational Health and Safety Management Systems – Requirements with Guidance for Use
- AS/NZS ISO 14001:2016 Environmental Management System – Requirements with Guidance for Use

and also the business' ERMF (13-10-CPPCUE0005) which is based upon AS/NZS ISO 31000:2018 Risk Management – Guidelines.

The INMS complies with the Electricity Safety (Management) Regulations 2019 and replaces the previous UE Electricity Safety Management Scheme (UE-ST-2921) and the CPPAL Electricity Safety Management Scheme (v3.27) documents previously approved by ESV. The scope of the INMS does not include the legislative obligations, non-electrical risks, nor risks associated with:

- Assets owned by generators, other Major Electricity Companies (MECs), or consumers.
- Corporate offices and general business equipment such as computers and motor vehicles.
- Depot facilities and vehicles, non-network related operations and activities.
- Corporate processes and associated IT systems for business communication, human resources and financial management.

The INMS, and associated management system standards, integrate the business policies, strategies, plans and procedures in a manner that facilitates the effective and efficient delivery of the INMS objectives, and;

- inform stakeholders including ESV, shareholders, staff, customers, the community, government and industry on how the INMS objectives and obligations are being achieved
- demonstrate a risk-based management approach in developing operating systems and management practices to identify the hazards and establish controls to minimise the risks associated with the operation of the electricity distribution network, as far as practicable
- define the approach established to manage the safe design, construction, commissioning, operation, maintenance and decommissioning of the electricity network.

13.2 Asset management system

The AMS aims to provide a clear 'line-of-sight' between the company's activities and the overall vision, organisational strategic plans and objectives, expressed in the:

- Asset Management Policy
- Asset Management Strategy and Objectives
- Strategic network management plan (**SNMP**)
- Asset Management Plans (**AMP**)
- Network Investment Plan (**NIP**)
- Capex / Opex Works Program (**COWP**)

13.3 Asset management policy principles

The Asset Management Policy defines the overarching principles for managing the network assets in a manner that is aligned with the Corporate Objectives and Asset Management System; Through the application of our asset management framework, we aim to meet business objectives and customer, stakeholder and employee needs.
We will achieve our commitment by adopting the following principles:

- Minimise safety risks as far as practicable.
- Provide safe, affordable (least long-term cost) and reliable network services, taking into consideration customer values and needs.
- Apply a risk-based approach to optimise the management of our network and systems.
- Build network resilience, including to the impacts of climate change.
- Engage and listen to our customers and communities to incorporate their input into decisions and adapt to their interests and needs.
- Invest in programs that sustainably optimise total lifecycle management.
- Comply with all relevant legislative and regulatory requirements as well as Australian and industry standards and any other requirements to which we subscribe.
- Develop high performance services by engaging with our employees and enabling them with the right skills and capabilities.
- Monitor and evaluate appropriate metrics to effectively manage the network and customer service performance.
- Continuously improve our asset management framework and activities by embracing innovation and technology to enhance our reputation, leading the industry in adopting and promoting asset management practices.

13.4 Asset management strategies, and objectives

The Strategic Network Management Plan (**SNMP**) guides the decision making processes to manage uncertainty and minimise the risk around capital deployment.

The network management strategies and objectives expand on the requirements of the Asset Management Policy:

- manage and operate the network safely
- meet our network reliability performance targets
- manage our assets on a total life cycle basis at least cost
- adapt to our customer's future needs
- manage our compliance obligations
- empower and invest in our employees
- monitor opportunities and drive continuous improvement.

13.5 Asset class management plans

The Asset Management Plans (**AMP**) detail the management activities for each asset class, from creation to disposal, including the asset maintenance and replacement requirements. The delivery of optimum outcomes for each asset class shall be guided by the asset management policies, strategies and objectives and combine them with an in-depth knowledge of the specific assets to identify the requirements that will ensure delivery of optimum outcome. The group of Asset Class Strategies and Plans are as follows:

- Line Assets;
- Distribution Plant Assets;
- Primary Assets;
- Secondary Assets;
- Communication Assets;
- Metering; and
- Operational Property.

13.6 Capex / Opex Works Program (COWP)

The COWP details the AMP list of projects that have been derived from the strategic planning processs. Data is collected and analysed to determine the required network modifications to produce a capital plan. It translates the asset strategies and asset management plans into a detailed 10 year investment plan. It strikes a balance between efficient and cost-effective investment, the required level of service, and an appropriate level of risk that is consistent with the Powercor risk appetite statement.

The COWP details the execution of the AMP on a two-year cycle, setting out the actions, responsibilities, resourcing, time scales for the activities in each program, and the expenditure associated with both capital and operational activities.

To optimise the COWP investment in replacement, demand and performance programs, three sets of requirements are balanced:

1. Customer requirements: customer expectations and current performance
2. Economic requirements: projects are subject to a level of economic analysis in accordance with regulatory requirements and prudent investment tests
3. Technical requirements: inputs that drive the network requirements, including:
    - Network performance: asset maintenance and replacement programs: driven by an analysis of fault/performance/cost data, based on reliability centred maintenance analysis
    - Safety compliance: INMS, and the Electricity safety legislation, detail the risk-based approach to managing electrical safety
    - Capacity planning: probabilistic analysis and contingency planning
    - Risk analysis: ERMF, and ISO 31000 for significant asset risks

13.7 System limitations identified through asset management

The system limitations (and the actions to resolve the limitations) listed within this DAPR have been identified by the asset management system.

- Chapters 7, 8, 9, and 10 outline the system limitations and network augmentation projects related to growth (demand and customer connections) and use of distribution services by embedded generating units.
- Chapter 15 outlines the system limitations and network replacement projects related to asset condition assessment as described in the asset management plans.

13.8 Contact for further information

Further information on the Powercor asset management strategy and methodology may be obtained by contacting Powercor Customer Service:

• General Enquiries 13 22 06

• Website https://www.Powercor.com.au/

Detailed enquiries may be forwarded to the appropriate representatives within Powercor.

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14 Asset Management Methodologies

An overview of the Powercor AMS has been provided in Chapter 13.

Powercor adopts a risk-based, whole of life, whole-system cost approach (**WLWS**) to asset management. Reliability Centred Maintenance (**RCM**) principles are used to manage the network assets over their life cycle; determine the asset maintenance requirements, and the actions that need to be taken to ensure cost-effective, reliable operation.

To assess asset performance, determine the required level of maintenance tasks, and the time intervals, Powercor;

- Identifies the key components, and functions of the asset class
- Performs a Failure Mode, Effects and Criticality Analysis (FMECA) to assess component failure, and the effect of the failures on asset function
- Determines cost-effective techniques (where possible) to manage failure modes
- Combines tasks into maintenance packages for implementation
- Reviews and improves asset and maintenance performance as necessary.

Where the performance of asset has deteriorated, or is no longer capable of performing the required function, the asset AMP shall be reviewed. The trigger for a review may be network changes, operational or business changes, learnings from failure investigations, field observations, deterioration in condition, an increase in the likelihood or consequence of asset failure. Depending on the outcome of the assessment, asset replacement may be necessary.

Distribution assets

The majority of distribution assets (‘poles and wires’ assets) are replaced upon asset failure, or where condition assessment has identified that the asset has reached the end of its service life. The condition assessment measures may vary between asset classes, examples include;

- Measurement of the sound wood: poles
- Dissolved Gas Analysis (**DGA**) and oil quality assessment of some primary plant and HV cables
- Partial Discharge (**PD**): primary plant and HV/MV cables
- Thermography
- Monitoring of insulation levels (gas/oil).

Condition assessment shall consider equipment technical thresholds, safety, risk and economic assessment, industry practice in developing a safe, reliable, least cost AFAP solution.

Upon indication that an asset has reached the end of its service life, actions may include:

- More frequent condition assessment or inspection
- Asset reinforcement, pole staking
- Asset de-rating or retirement

- Overhaul / refurbishment
- Non-network solutions
- Asset replacement.

Zone substation assets

Due to the increased inter-connectivity, redundancy, and capability to monitor asset condition, the design of zone substations facilitates the use of a number of options to manage the risks associated with assets approaching the end of their useful life.

Since zone substations provide more information on asset condition, risk assessment and economic optimisation can be conducted at a more detailed level compared to other distribution assets;

- Dielectric Loss Angle (**DLA**) testing of bushings
- Dissolved Gas Analysis (**DGA**), Sweep Frequency Response Analysis (**SFRA**), moisture content assessment and paper insulation testing
- PD testing and DLA testing of switchgear
- Asset performance history
- Analysis of load-at-risk.

Given the complexity and structure of larger zone substations, a greater variety of practical options may be used to identify the least-cost solution to managing risk;

- Increased ongoing condition assessment
- Overhaul / refurbishment
- Retrofit of on-line condition monitoring systems
- Component replacement
- Non-network solutions
- Asset de-rating or retirement
- Load transfers and increased redundancy
- Contingency plans and increased spares holdings.

Assessments of potential solutions shall generally be performed over a forward looking period, typically 10 years. Optimal timing for the works shall be determined by identifying the least-cost option over the period.

Generally, the asset is retired and/or replaced based on the most economic solution that maintains safety and reliability standards, considering;

- Cost of the intervention, task or measures available to address the risk
- Assessment of how various options reduce the quantified risk.
- Evaluating the risk associated with the asset, including an assessment of:
  - Likelihood of occurrence
  - Safety and environmental impact
  - Substation design and redundancy
  - Network economic impact
  - Other costs

The asset replacement outlined in **Error! Reference source not found.** Chapter is a forecast based on the historic number of asset replacements (typical number for high volume assets such as poles), and based on an assessment of the currently available condition data for specific assets. Next chapter includes methodologies used for the replacement of each asset class.

15 Retirements and De-ratings

This chapter sets out the planned network retirements over the forward planning period. The reference to asset retirements includes asset replacements, as the old asset is retired and replaced with a new asset.

In addition, this chapter discusses planned asset de-ratings that would result in a network constraint or system limitation over the planning period.

The System Limitation Report details those asset retirements and de-ratings that result in a system limitation.

Where more than one asset of the same type is to be retired or de-rated in the same calendar year, and the capital cost to replace each asset is less than $200,000, then the assets are reported together below.

15.1 Individual assets

A summary of the individual assets that are planned to be retired in the forecast planning period is provided in the table below. It indicates how the current retirement date has changed from the date specified in the 2022 DAPR. A more detailed assessment, including a consideration of non-network alternatives will be carried out at the business case and RIT-D stage. Further changes to the planned retirements and de-ratings below may arise from this further assessment.

Table 15.15.1 Planned asset retirements and de-ratings

Location	Asset	Project	Retirement date	2022 DAPR
Inglewood (**IWD**) Regulator Substation	IWD Regulator	Replacement	2025	2025

Location	Asset	Project	Retirement date	2022 DAPR
Robinvale (**RVL**) Zone Substation	Transformer 2	Replacement	2028	2026
Geelong (**GL**) Zone Substation	GL CB A 66kV Circuit Breaker	Replacement	2027	2026
Geelong (**GL**) Zone Substation	GL CB B 66kV Circuit Breaker	Replacement	2027	2026
Geelong (**GL**) Zone Substation	GL CB C 66kV Circuit Breaker	Replacement	2027	2026
Ouyen (**OYN**) Zone Substation	OYN1 22kV Circuit Breaker	Replacement	2026	2024
Ouyen (**OYN**) Zone Substation	OYN3 22kV Circuit Breaker	Replacement	2026	2024
Ouyen (**OYN**) Zone Substation	OYN5 22kV Circuit Breaker	Replacement	2026	2024
Ouyen (**OYN**) Zone Substation	OYN7 22kV Circuit Breaker	Replacement	2027	2024
Terang (**TRG**) Zone Substation	Transformer 1	Replacement	2027	-

For the forward planning period, there are no committed investments worth $2 million or more to address urgent and unforeseen network issues.

The excel based detailed system limitation reports for asset replacements can be found at the link below by searching for asset replacement system limitation report:

https://spaces.hightail.com/space/UaPnYI6yeV

15.1.1 Inglewood (IWD) Zone Substation Regulator

The Inglewood (**IWD**) regulator connected to 66KV sub-transmission lines from Charlton zone substation (**CTN**) and Bendigo terminal station (**BETS**) has been in service for 79 years.

CBRM analysis determined that the 66KV Regulator has a health index of 9.1 rising to 10.2 in next five years and is forecast to require replacement in 2025.To address the anticipated system constraint by retiring the IWD regulator, Powercor considers that the best network solution is to replace the regulator at IWD, which has an estimated cost of $1.59 million.

Powercor's preferred option is to replace the regulator in 2025. Without a regulator at Inglewood the entire CTN and Coonooer Bridge Wind Farm system would not be able to be supported and would be off supply. As there are no non network solution able to provide the system support functions of this regulator, a system limitations report is not provided. Load details of CTN load are however available from the load forecast sheet.

15.1.2 Geelong (GL) Zone Substation CB A, B and C 66kV Circuit Breaker

The Geelong (**GL**) zone substation is served by 66KV sub-transmission lines from Geelong Terminal Station (**GTS**) connected in a loop with Geelong B (**GB**) zone substation and Geelong City (**GCY**) zone substation supplying the Geelong City area.

The GL zone substation is comprised of two 20/40 MVA transformers operating at 66/22kV connected to a 66kV sub-transmission system via three line-circuit breakers and one bus tie circuit breaker.

CBRM analysis determined that the 66kV CB A, CB B and CB C line circuit breakers have their current health index at 6.1 rising to 7.1 in next five years and is forecast to require replacement in 2027.

Currently these circuit breakers are inspected and tested according to six yearly maintenance plans. These old oil-filled circuit breaker failures will risk the reliability of the network due to the inadequate spare parts availability and the unavailability of internal and external skilled resources to repair safely.

According to Powercor's zone substation switchgear asset class strategy, the aim is to reduce the oil filled old circuit breaker population from the network to significantly reduce the associated safety and reliability risks in event of an oil filled circuit breaker failed catastrophically.

Powercor estimates that with a breaker out of service, there will be 32.6 MVA of load at risk in 2027 and for 8,760 hours it won't be able to supply customers at GL zone substation for a sub transmission line failure.

To address the anticipated constraint at GL zone substation, Powercor considers that the following network solutions could be implemented to manage the risk:

- replace 66kV Bus tie Circuit breakers A, B and C at GL for an estimated cost of $0.43 million each
- contingency plan to transfer load away via 22kV links to the adjacent Zone Substation up to a maximum capacity of 32.6 MVA.

Powercor preferred option is to replace the three 66kV bus tie circuit breakers A, B and C in 2027.

15.1.3 Robinvale (RVL) Zone Substation Transformer 2

The zone substation in Robinvale (**RVL**) is served by a sub-transmission line from Bannerton Solar Park (**BSP**), Wemen Terminal to Wemen Solar Farm (**WETS-WMN**) and currently consists of one 20/33 MVA transformer and two 5/6.5 MVA transformers at transformer 2 and transformer 3 positions in service for 70 years. It supplies the area of Robinvale extending into surrounding areas.

CBRM analysis determined that the No2 transformer has a health index of 6.6 rising to 7.5 in next five years and is nonetheless forecast to require replacement in 2028. Retirement of this transformer would result in the remaining station load being carried by the two remaining transformers, which would place customers at risk of extended outages during times of unplanned network contingencies.

With the No2 transformer retired, Powercor estimates that in 2028 there will be 11 MVA of load at risk and for 1,501 hours in the year it will not be able to supply all customers from the zone substation if there is a failure of one of the two remaining transformers at RVL.

To address the anticipated system constraint at RVL zone substation, Powercor considers that the following network solutions could be implemented to manage the risk:

- contingency plan to install mobile generation at 22kV to RVL feeders
- replace No2 Transformer at RVL for an estimated cost of $3.73 million
- contingency plan to transfer load away via 22kV links to the adjacent Wemen Zone Substation (**WMN**) up to a maximum capacity of 4.3 MVA.

Powercor's preferred option is to replace the No2 Transformer at RVL in 2028. The use of contingency load transfers will mitigate the risk should the asset fail ahead of its forecast replacement date. For more details and data on the limitation and preferred network investment please refer to the System Limitation Report.

A demand side initiative to reduce the forecast maximum demand load by 11 MW at RVL zone substation would defer the need for this capital investment by one year.

15.1.4 Ouyen (OYN) Zone Substation 1, 3, 5 and 7, 22kV Circuit Breakers

The Ouyen (OYN) zone substation is served by a single radial sub-transmission line from the Hattah zone substation (HTH). Currently, the OYN zone substation is comprised of two 10/13.5 MVA transformers operating at 66/22 kV, supplying the surrounding area to OYN zone substation.

The old OYN 22kV feeder circuit breakers were replaced in 2021 with refurbished vacuum circuit breakers. These refurbished breakers are 35 years old, and replacement was temporary to reduce the network risks from old 22kV circuit breakers. Currently these 22kV circuit breakers are inspected and tested according to three yearly maintenance plans. A 22kV circuit breaker failure will risk the reliability of the network due to the inadequate spare parts availability and the unavailability of skilled resources to repair safely.

CBRM analysis determined that the current circuit breakers have a current health index of 5.4 raising to 6.3 in the next five years.

Powercor estimates that with a 22kV circuit breaker out of service, there will be 8.5 MVA of load at risk in 2026 and for 8,760 hours it won't be able to supply customers.

To address the anticipated constraint at OYN zone substation, Powercor considers that the following network solutions could be implemented to manage the risk:

- replace OYN1, OYN3, OYN5 and OYN7 22kV circuit breakers for an estimated cost of $0.21 million each

Powercor preferred option is to replace three of the 22kV feeder circuit breakers in 2026 and the last one in 2027.

15.1.5 Terang (TRG) Zone Substation Transformer 1

The Terang (**TRG**) zone substation is served by two sub-transmission lines from the Terang Terminal Station (**TGTS**) and Warrnambool (**WBL**) and currently consists of one10/13.5 MVA transformer 1 and one 25/33 MVA transformer 2.

CBRM analysis determined that the No1 transformer has a health index of 11.1 rising to 12.8 in next five years and is nonetheless forecast to require replacement in 2028.

With the No1 transformer retired, powercor estimates that in 2027 there will be 20.5 MVA of load at risk and for 8,760 hours in the year it will not be able to supply all customers from the zone substation if there is a failure of the remaining transformer.

To address the anticipated system constraint at TRG zone substation, Powercor considers that the following network solutions could be implemented to manage the risk:

- contingency plan to transfer load away via 22kV links to adjacent zone substations of Cobden (COB) and Camperdown (CDN) up to a maximum transfer capacity of 5.1MVA
- augment TRG by replacing the No.1 13.5MVA transformer with a larger 25/33MVA unit at an estimated cost of $4 million.

Powercor's preferred option is to augment TRG by replacing the No.1 13.5MVA transformer with a larger 25/33MVA unit. However, given that the forecast annual hours at risk is low, this project is not expected to occur during the forecast period. Although the expected demand will exceed the station's N1 cyclic rating, the use of contingency load transfers will mitigate the risk in the interim period. Please refer to the System Limitations Template for further information regarding the preferred network investment.

15.2 Groups of Assets

This section discusses planned retirements and replacements for groups of assets.

15.2.1 Poles and towers

Powercor intends to replace poles and towers in various locations across the network in each year of the forward planning period. The number of poles and towers replaced each year is determined by condition assessments undertaken on each pole/tower inspected and policy for sustainable lifecycle management. The forecast number of poles/towers to be replaced in the coming 5 years is expected to increase in line with changes to poles management policies and requirements stipulated by Energy Safe Victoria to improve the performance of aged, lower durability timber poles in Hazardous Bushfire Risk Areas (HBRA).

Powercor has a range of poles in its network, including hardwood, steel and concrete, supporting different voltages of conductor. All towers on the network are steel lattice structures.

Poles and towers are assessed using the RCM methodology which forms an input into the CBRM model to inform the policy position. The inspection frequency is based on priority and economic optimisation to deliver the legislative obligations under the Electricity Safety Act 1998. This methodology was discussed in the previous chapter. Where the pole or tower is inspected and found to be defective, and a routine maintenance option is not viable to remedy the defect (ie pole reinforcement), it is necessary and prudent to replace the pole or tower.

15.2.2 Pole top structures

- Pole top structures includes the following assets, which are managed as set out below:

- Wood or steel cross arms are inspected at the same time as the pole using the RCM methodology discussed in the previous section.
- Insulators (generally made of porcelain), are inspected at the same time as the pole using the RCM methodology discussed in the previous section.
- Surge arrestors are attached to the pole and provide an alternate current path for the electricity to ground in the event of a lightning strike. These are generally replaced after they fail, otherwise they are replaced based upon age.
- Other pole top structure equipment include: fuses, dampers, armour rods, spreaders, brackets, etc. These are all inspected at the same time as the pole.
- Replace all EDO fuses with fault tamers in Electric Line Construction Areas (ELCAs), and progressively replace EDO fuses with fault tamers in Hazardous Bushfire Risk Areas (HBRAs) other than ELCAs, as part of the regular inspection and maintenance program.

- Powercor intends to replace pole top structures in various locations across its network in each year of the forward planning period. The number of pole top structures replaced each year is determined by condition assessments undertaken on each pole top structure inspected. The forecast number of pole top structures to be replaced in the coming 5 years is expected to increase in line with changes to pole management policies.

15.2.3 Switchgear

Switchgear can be classified as overhead or ground-mounted. Switchgear includes the following assets classes:

- **Automatic Circuit Reclosers (ACR)** – interrupts fault current using SF6 gas or Vacuum to automatically restore supply post removing system transients
- **Air Break Switches (ABS**) – provide electrical isolation using air to break load current
- **Circuit Breakers** – interrupts fault current protecting an electrical circuit from damage caused by overcurrent/overload or short circuit
- **Pole Mounted Gas Switches** – provides electrical isolation using SF6 gas to break load current. Switches can be manually operated or configured with motors drives and control systems for remote operaion.
- **Ring Main Units and Metal Clad Swicthes** – provides electrical isolation and earthing using SF6 gas or oil to break load current. Switches can be manually operated or configured with motors drives and control systems for remote operaion.
- **Isolators** – provides single phase electrical isolation using air as an insulating medium. Some isolators can be configured with an arc shoot to provide some level or load breaking capability

Most switchgear assets are replaced based on condition, which is monitored through routine maintenance and inspection. When a defect is found and it cannot be rectified through maintenance, a refurbishment or replacement of the asset is prudent.

The replacement need and timing are prioritised through risk and economic assessments. The location and the timing of the asset retirement is only determined when a defect is identified.

Powercor intends to replace most switchgear assets in each year of the forward planning period in line with historical volumes for most assets. Some assets classes have proactive replacement programs established where higher than historical replacement volumes are forecast. This address issues such as poor performance, obsolescence and/or risk. Switchgear with proactive replacement programs established include:

- Air Break Switches
- Ring Main Units and Metal Clad Switches

15.2.4 Overhead services

Overhead services, which are required to connect a customer supply point to the network are inspected at the same time as the pole and pole top structures using the same RCM methodology discussed in the previous sections.

Powercor intends to replace overhead services in various locations across its network in each year of the forward planning period. The number of overhead services replaced each year is determined by condition assessments undertaken on each overhead service inspected. The forecast number of overhead services to be replaced in the coming 5 years is expected to increase above the historical replacements within the following two categories.

- Grey PVC services: driven by deteriorated insulation associated with “dog-bone” terminations and UV damage to the insulation of the service itself
- Neutral screened services: driven by the application of AMI meter analytics to detect, assess and replace services where the neutral is suspect, to address safety issues.

15.2.5 Overhead conductor

Overhead conductors are an integral part of the distribution system. Overhead conductors may be bare, covered or insulated and are made of aluminium, copper and galvanised steel.

Conductor replacements are based on two methodologies:

- through inspection, asset failures or defect reports
- proactively through risk-assessment using health indices.

Powercor plans to replace sections of overhead conductors each year over the forward planning period. The location and timing of conductor replacement will be determined based on condition assessments and risk. The forecast number of sections of overhead conductor to be replaced in the coming 5 years is in line with historical replacements with an expected increase from 2024.

As data and modelling improves, a better understanding of the location and timing of the conductor replacement at the planning stage of the proactive replacement program is expected in the near term.

15.2.6 Underground cable

Underground sub-transmission cables are performance monitored and condition assessed by a scheduled cyclic testing program. Cables found by the test program to be in unacceptable condition are generally repaired as the issue is normally location specific or the result of damage by third parties. Sections of cable may be replaced from time to time on an unplanned basis as a response to identified defects or damage.

The GTS-GCY 66kV sub-transmission cable installed at GCY zone substation is planned for replacement in 2024 due to increased partial discharge activity identified through routine and additional condition monitoring activities.

HV and LV Underground cables are performance monitored and condition assessed when the cable is exposed for augmentation works or defect repairs. Cables identified in unacceptable condition are prioritised for replacement using an economic assessment of risk associated with the identified defect.

Over the forward planning period Powercor plans to replace most underground cables in line with historical volumes.

15.2.7 Other underground assets

Other underground assets include the following:

- Cable-head terminations, which are the termination of an underground cable. Repairs and replacements are to be in line with historical volumes.
- Distribution service pits are the point where the underground service connects to the customer premises, typically of concrete and plastic construction. Improvements to inspections were implemented in mid 2021 which has identified an increase in repair and replacement volumes in the forward planning period.
- Low-voltage pillars are typically concrete or steel, where low voltage underground cables are terminated. Repairs and replacements are expected to increase through the forward planning period due to improvements in inspection and defect reporting.
- Services (underground), which are required to connect a customer supply point (underground pit) to the network, are replaced based on condition when inspected or through defect reports.

Underground asset replacements are prioritised using an assessment of risk associated with the identified defect. The timing of replacement is determined by the risk assessment.

15.2.8 Transformers and other distribution plant

In the forward planning period, Powercor plans to replace most distribution plant assets in line with historical volumes. Distribution plant assets include a variety of assets listed below:

- Distribution substation transformers include indoor, kiosk, ground mounted (compound) or pole mounted types. Transformers are replaced based on condition, as identified through scheduled inspections and defect reporting. Replacement prioritisation is determined by conducting risk and economic assessments. Higher than historical volumes of replacements for kiosk and pole mounted transformers are expected as a result of improvements to reporting and management of oil leaks.
- Pole top capacitors can be attached to the network to improve line capacitive balance, power factor, usually on longer lines. These are replaced based on condition when inspected or through defect reports. Replacement prioritisation is determined by conducting risk and economic assessments.
- Earthing cables, which are required as one measure to prevent de-energised assets from becoming energised in the event of insulation breakdown or contact with live assets, are replaced following an inspection and/or condition monitoring. SWER defects are increasing due to

- Regulators, which adjust voltage levels according to measured network dynamics, are replaced based on condition with a dedicated program to remove obsolete regulators i.e. regulators that are no longer supported by the manufacturer and no longer have spares available.

The location and the timing of the replacement of distribution plant assets are determined at the time of inspection and detection of defect, or upon failure of the asset.

15.2.9 Zone substation switchyard equipment

Powercor plans to replace zone substation switchyard equipment each year in the forward planning period. Zone substation switchyard equipment assets include a variety of assets listed below:

- Surge arrestors, which are required to protect primary plant from voltage surges, are generally replaced after they fail. They can also be replaced based on age and condition, or opportunistically where other asset replacements take place at the zone substation.
  - As part of our REFCL installation program, we are planning to replace surge arrestors at Bendigo terminal station (**BETS**), Charlton (**CTN**), Bendigo (**BGO**), Ballarat South (**BAS**), Ballarat North (**BAN**), Geelong (**GL**) Corio (**CRO**), Koroit (**KRT**), Stawell (**STL**), Waurn Ponds (**WPD**), Hamilton (**HTN**), Ararat (**ART**), Merbein (**MBN**) and Terang (**TRG**) before the end of 2023.
- Busses, which allow multiple connections to a single source of supply, are usually replaced as part of the associated zone substation equipment being replaced, e.g. 22kV busses usually form part of modular switchboards and thus will be included as part of switchboard replacements.
- Joints, terminations and connector assets are replaced on inspection, or as part of the replacement of the assets they are connected to.
- Steel structures, which are required to hold energised assets in place, are replaced based on inspection and observed condition.

The location and the timing of the replacement of zone substation assets are determined at the time of inspection or upon identification of defects.

15.2.10 Protection and control room equipment and instrumentation

Protection and control systems are designed to detect the presence of power system faults and/or other abnormal operating conditions and to automatically isolate the faulted network by the opening of appropriate high voltage circuit breakers. Powercor plans to replace protection and control room equipment and instruments each year over the forward planning period. Volumes are expected to be similar to historical volumes. This includes the following assets:

- Protection relays are replaced based on age and/or economic assessment of risk.
  - Powercor's relay replacement program focusses on electro-mechanical, electronic and end of life digital protection relays. The risk profile of these types of relays is forecast to significantly increase as the technology is approaching end of life.
  - Relays will be replaced at the following zone substations over the forward planning period: Altona Chemicals (**AC**), Ballarat North (**BAN**), Bacchus Marsh (**BMH**), Cohuna (**CHA**), Cobram East (**CME**), Corio (**CRO**), Drysdale (**DDL**), Echuca (**ECA**), Ford Norlane (**FDN**), Ford North Shore (**FNS**), Geelong B (**GB**), Geelong City (**GCY**), Geelong (**GL**), Kyabram (**KYM**),

Laverton (**LV**), Mildura (**MDA**), Melton (**MLN**), Numurkah (**NKA**), Ouyen (**OYN**), Portland (**PLD**), St. Albans (**SA**), Stawell (**STL**), Werribee (**WBE**), Winchelsea (**WIN**) and Woodend (**WND**).

  - As the need to replace the assets will be reassessed on a risk-based approach closer to the replacement period, the date of replacement is unknown at time of writing.

- Capacitor Bank controllers (or VAR controllers) are usually run-to-failure and as such it is prudent for Powercor to maintain asset spares.
- Battery banks are replaced based on the results of condition tests.
- Voltage/Current transformers: are usually run-to-failure and as such it is prudent for Powercor to maintain asset spares.

Aside from the proactive replacement of protection relays at zone substation locations, the timing and the location of the replacement of other assets are determined through routine inspection and detection of defects, or upon asset failure.

15.3 Planned asset de-ratings

Powercor has no planned asset deratings in the forward planning period.

15.4 Committed projects

This section sets out a list of committed investments worth $2 million or more to address urgent and unforeseen network issues. Powercor does not have any committed projects to address urgent and unforeseen network issues.

15.5 Timing of proposed asset retirements/ replacements and deratings

Powercor is now also required to provide detailed information on its asset retirements / replacement projects and deratings in its DAPR as described above. The timing of these may change subject to updated asset information, portfolio optimisation and realignment with other network projects, or reprioritisation of options to mitigate the deteriorating condition of the assets.

Powercor has made improvements to the risk assessment quantification. These changes primarily involve a refinement of the estimated failure probability for transformers, taking into account failures and replacements, and the inclusion of analysis at a substation level, considering common-cause failure risk for substations with identical assets. As a result, some asset retirements have been deferred, and other future retirements have been brought forward.

The table below summarises the change in timing of proposed major network retirements/replacements:

Table 15.2 - Changes in timing of asset retirements / replacements and deratings

Proposed Asset Replacement	2022 DAPR	2023 DAPR
Robinvale (**RVL**) Zone Substation transformer 1	2026	2027
Warrnambool (**WBL**) transformer 1	2024	removed
Eaglehawk (**EHK**) 66kV CB	2025	removed
Geelong (**GL**) 66kV CB's	2026	2027
Ouyen (**OYN**) 22kV CB's	2024	2026/7
Terang (**TRG**) transformer	-	2027

16 Regulatory Tests

This chapter also sets out possible RIT-D assessments that Powercor may undertake in the future.

Large network investments are assessed using the RIT-D process. The RIT-D relates to investments where the cost of the most expensive credible option is more than $6 million. The RIT-D has historically been used for large augmentation projects, and was extended to include replacement projects from 18 September 2017.

Transitional arrangements apply for the introduction of the RIT-D for replacement projects where the following projects are excluded:

- replacement projects that have been "committed" to by a distributor on or prior to 30 January 2018
- the second tranche of Rapid Earth Fault Current Limiters (**REFCL**s), in so far as they relate to replacement.

The excluded projects are listed in this chapter, as well as published on our website. There is no material impact on connection charges and distribution use of system charges that have been estimated.

16.1 Current regulatory tests

Powercor intends to complete a RIT-D to support the development of Ballarat East to provide more REFCL capacity in Ballarat.

Table 16.1 Current RIT-D projects

Project name	Description	Scheduled completion date
Ballarat East (**BAE**) zone substation	Establish new Ballarat East zone substation and associated 66kV/22kV works to maintain ongoing REFCL compliance in the Ballarat area	1 May 2024

16.2 Future regulatory investment tests

The following projects are planned for future Regulatory Tests in the period 2024 through to 2028.

Table 16.2 Future RIT-D projects

Project name	Description	Scheduled start date
Mount Cottrell Zone substation (Stage 1)	Establish new Mount Cottrell zone substation for large customer supply	Jan 2024
Mount Cottrell Zone substation (Stage 2)	Expand Mount Cottrell zone substation and offload WBE, LV and TNA	Jan 2024
Colac (**CLC**) new isolating substation with REFCL	Upgrade to Colac to maintain ongoing REFCL compliance	Feb 2024
Gisborne (**GSB**) new REFCL and switchboard	Upgrade to Gisborne and transfers from Woodend to maintain ongoing REFCL compliance at Woodend	Feb 2025
Eaglehawk (**EHK**) REFCL and 3rd transformer	Upgrade to Eaglehawk to maintain ongoing REFCL compliance	Feb 2025
Colac (**CLC**) new isolating substation with REFCL	Upgrade to Colac to maintain ongoing REFCL compliance	Feb 2026

16.3 Excluded projects

There are presently no excluded projects from the RIT-D.

17 Network Performance

This section sets out Powercor's performance against its targets for reliability and quality of supply, and its plans to improve performance over the forward planning period.

17.1 Reliability measures and performance

Powercor is subject to a range of reliability measures and standards.

The key reliability of supply metrics to which Powercor is incentivised under the Service Target Performance Incentive Scheme (**STPIS**) are:

- System average interruption duration index (**SAIDI**): Unplanned SAIDI calculates the sum of the duration of each unplanned sustained customer interruption (in minutes) divided by the total number of distribution customers. It does not include momentary interruptions that are one minute or less
- System average interruption frequency index (**SAIFI**): Unplanned SAIFI calculates the total number of unplanned sustained customer interruptions divided by the total number of distribution customers. It does not include momentary interruptions that are three minutes or less. SAIFI is expressed per 0.001 interruptions
- Momentary average interruption frequency index event (**MAIFI**e): calculates the total number of momentary interruption events divided by the total number of distribution customers (where the distribution customers are network or per feeder based, as appropriate).

The reliability of supply parameters are segmented into urban, rural short and rural feeder types.

The table below shows the reliability service targets set by the AER for Powercor in its Distribution Determination in April 2021.[15] Powercor reported to the AER its 2022/23 Financial Year performance against those targets in the 2022/23 Financial Year Regulatory Information Notice (**RIN**), and these figures are included in the table.

15 AER, Powercor Australia Limited, Distribution determination 2021–2026, Final, April 2021.

Table 17.1 Reliability targets and performance

Feeder	Parameter	AER target (2021-2026)	2021-2022 performance
Urban	SAIDI	69.227	68.696
	SAIFI	0.823	0.892
	MAIFIe	1.200	1.056
Rural Short	SAIDI	104.142	91.847
	SAIFI	1.147	0.997
	MAIFIe	2.508	1.642
Rural Long	SAIDI	240.916	220.992
	SAIFI	2.025	2.039
	MAIFIe	4.393	2.908

In 2022/23 FY, Powercor achieved its targets for Urban SAIDI and MAIFI, Rural Short SAIDI, SAIFI & MAIFI, and Rural Long SAIDI and MAIFI parameters.

17.1.1 Corrective reliability action undertaken or planned

Actual network reliability performance is the result of many factors and reflects the outcomes of numerous programs and practices right across the network. To achieve long term and sustainable reliability improvements, Powercor continues to refine and target existing asset management programs as well as reliability specific works.

The processes and actions which Powercor undertakes to sustain reliability include (but are not limited to):

- undertaking the various routine asset management programs, including:
  - inspection of poles and pole tops
  - maintenance and replacement programs for overhead and underground lines, primary plant and secondary systems
  - Implementation of enhanced monitoring and replacement program of capacitive voltage transformers in zone subs to provide improved safety and reliability.
- deployment of portable auxiliary cooling fans at several substations to assist in cooling heavily loaded transformers
- targeted installation of smart technologies to improve network monitoring, control and restoration of supply including intelligent circuit reclosers, gas switches and line fault indicators at strategic locations
- targeted reduction of the exposure to faults on the distribution network by using:
  - thermography programs to detect over-heated connections

- partial discharge detection program for assets in zone substations, such as indoor switchgear, including several continuous on line monitoring systems
- partial discharge detection program for underground cables
- vegetation management programs to improve line clearances
- targeted lines for bark inspections such as in the Otways and Macedon ranges
- animal and bird mitigation measures to reduce the risk of 'flash-overs
- conductor clashing mitigation measures to reduce the risk of 'flash-overs' and bushfire risk
- targeted insulator washing and pole-top fire mitigation to reduce the risk of pole fires
- dehydration of power transformer.

- use of innovative solutions such as auxiliary power generation or by-pass cables to maintain supply where practicable
- conduct fault investigations of significant outages and plant failures to understand the root cause, in order to prevent re-occurrences
- continual improvements to outage management processes
- undertake asset failure trend analysis and outage cause analysis to identify any emerging asset management issues and to mitigate those through enhancing the related asset management plans, maintenance policies or technical standards.

Evaluation of the 2022/23 reliability improvement initiatives should be considered in the context of the longer term goals stipulated above and the volatility caused by uncontrollable events such as severe storms and the effect of third party events.

17.2 Quality of supply measures and standards

The main quality of supply measures that Powercor control are:

- Voltages and voltage unbalance, including measuring customer voltage and network voltage using AMI data as well as power quality meters at the zone substations
- Harmonics, and
- Flicker.

17.2.1 Voltage

Voltage requirements are governed by the VEDCoP and the NER. The NER requires that Powercor adheres to the 61000.3 series of Australian and New Zealand Standards.

In addition, the VEDCoP requires that Powercor must maintain nominal voltage levels at the point of supply to the customer's electrical installation in accordance with the Electricity Safety (General) Regulations 2019 or, if these regulations do not apply to the distributor, at one of the following standard nominal voltages:

a) 230V

b) 400V
c) 460V
d) 6.6kV
e) 11kV
f) 22kV or
g) 66kV.

Variations from the standard nominal voltages listed above are permitted to occur in accordance with the following table as per the VEDCoP with the exception of REFCL areas.

Table 17.2 Permissible voltage variations[16]

STANDARD NOMINAL VOLTAGE VARIATIONS					
	Voltage Level in kV	**Voltage Range for Time Periods**			**Impulse voltage**
		Steady State	**Less than 1 minute**	**Less than 10 seconds**	
1	<1	*AS* 61000.3.100*	+ 13% - 10%	Phase to Earth +50%, -100% Phase to Phase +20%, -100%	6 kV peak
2**		+ 13% - 10%			
3	1 – 6.6	± 6% (± 10% Rural Areas)	± 10%	Phase to Earth +80%, -100% Phase to Phase +20%, -100%	60 kV peak
4	11				95 kV peak
5	22				150 kV peak
6	66	± 10%	± 15%	Phase to Earth +50%, -100% Phase to Phase +20%, -100%	325 kV peak

* In REFCL areas while the REFCL is in operation, the 22kV phase to earth voltages may equal the phase to phase voltage for periods greater than 10 seconds. As per the clause 20.4.3 of VEDCoP, during the period in which a REFCL condition is experienced on the 22-kV distribution network, the phase to earth voltage variation in row 5 of the above table does not apply. The phase to phase voltage variations only apply to that part of the 22kV distribution system experiencing the REFCL condition.

Powercor must use best endeavours to minimise the frequency of ***voltage*** variations allowed for periods of less than 1 minute (other than in respect of AS 61000.3.100 where the time period of less than one minute does not apply).

[16] Table 2 Clause 20.4.2 of the Victorian Electricity Distribution Code of Practice.

Powercor is able to measure voltage variations at zone substations, as many have power quality meters installed. This enables Powercor to address any systemic voltage issues. The table below provides the number of instances of voltage variations at Powercor zone substations in the 2022-23 financial year, although many of these instances would have occurred from abnormalities or transients in the system.

Table 17.3 Zone substation voltage variations in 2022-23 FY

Voltage variations	Number of occurrences
Steady state (zone substation)	12185
One minute (zone substation)	204
10 seconds (zone substation) Min<0.7	539
10 seconds (zone substation) Min<0.8	329
10 seconds (zone substation) Min<0.9	1451

17.2.2 Customer voltage performance at low voltage

AS 61000.3.100 requires that the 99th percentile voltage must be less than 253V and the 1st percentile voltage must be above 216V. This is a deviation from the previous requirements that stipulated a hard limit of 216V and 253V. The VEDCoP stipulates the above-mentioned voltage levels should be at the meter closest to and applicable to the point of supply as mentioned in clause 20.4.1 of VEDCoP. AS 61000.3.100 also recognises that for distribution companies like Powercor with hundreds of thousands of customers spread over a large geographic area, achieving 100% compliance for all customers at all times is not economically or practically possible. Therefore, a network is considered to be ‘functionally compliant’ if it can achieve voltage within each limit for 95% of sites.

Figure 17.1 and 17.2 below shows Powercor’s performance for both 99th percentile voltage (V99%) and 1st percentile voltage (V1%) with respect to the 95% functional compliance target. Additionally, the average voltage data is provided in Figure 17.3 as required by VEDCoP.

Figure 17.1 Monthly V99% customer voltage performance at low voltage

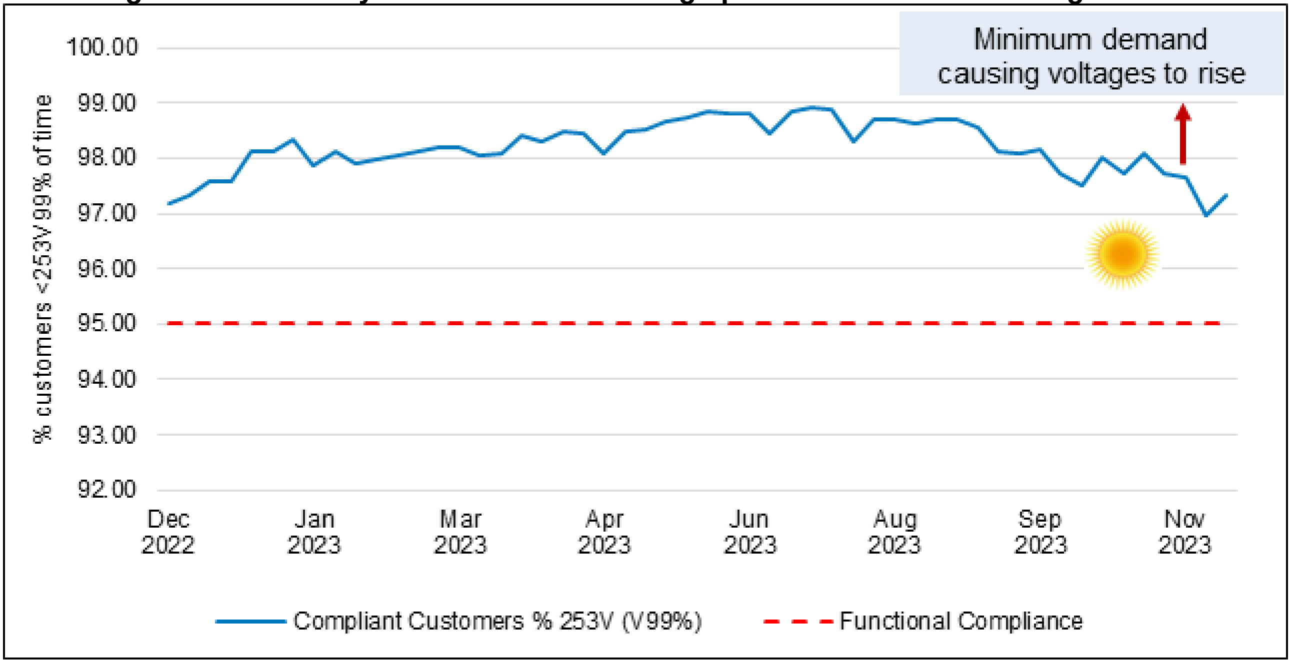


Figure 17.2 Monthly V1% customer voltage performance at low voltage

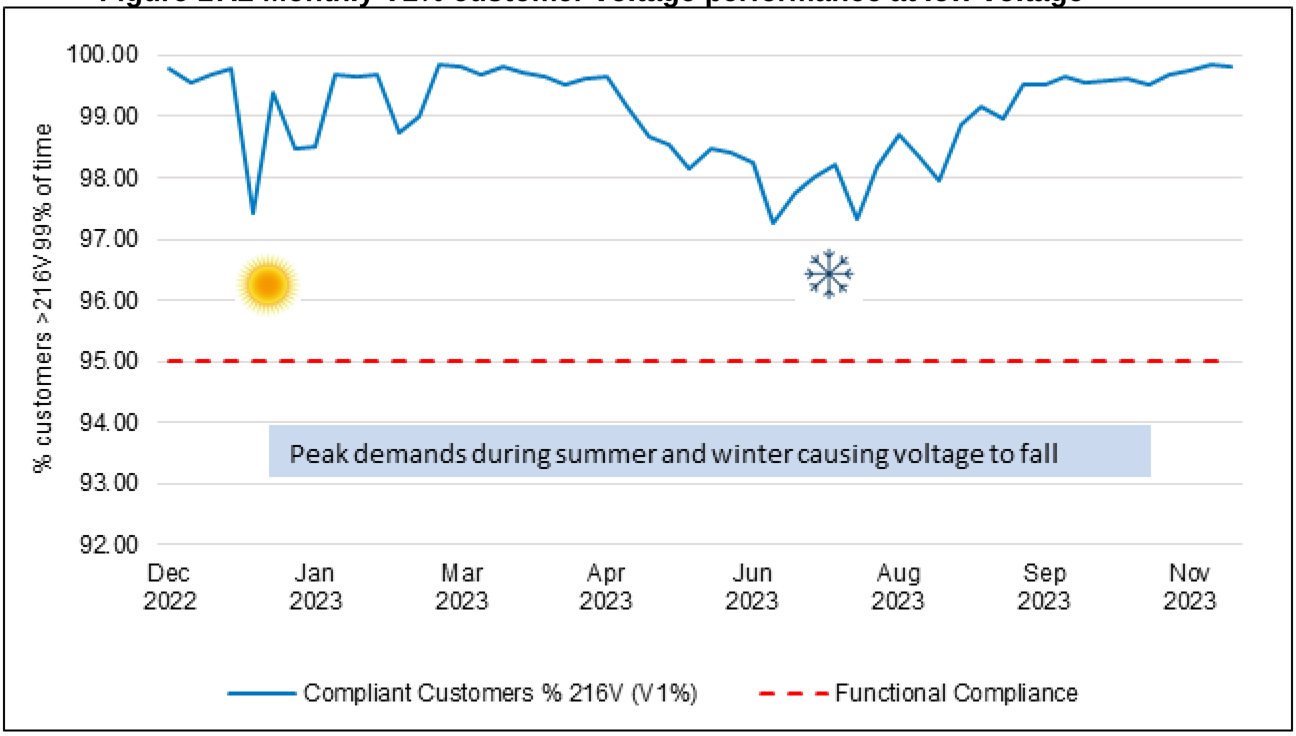
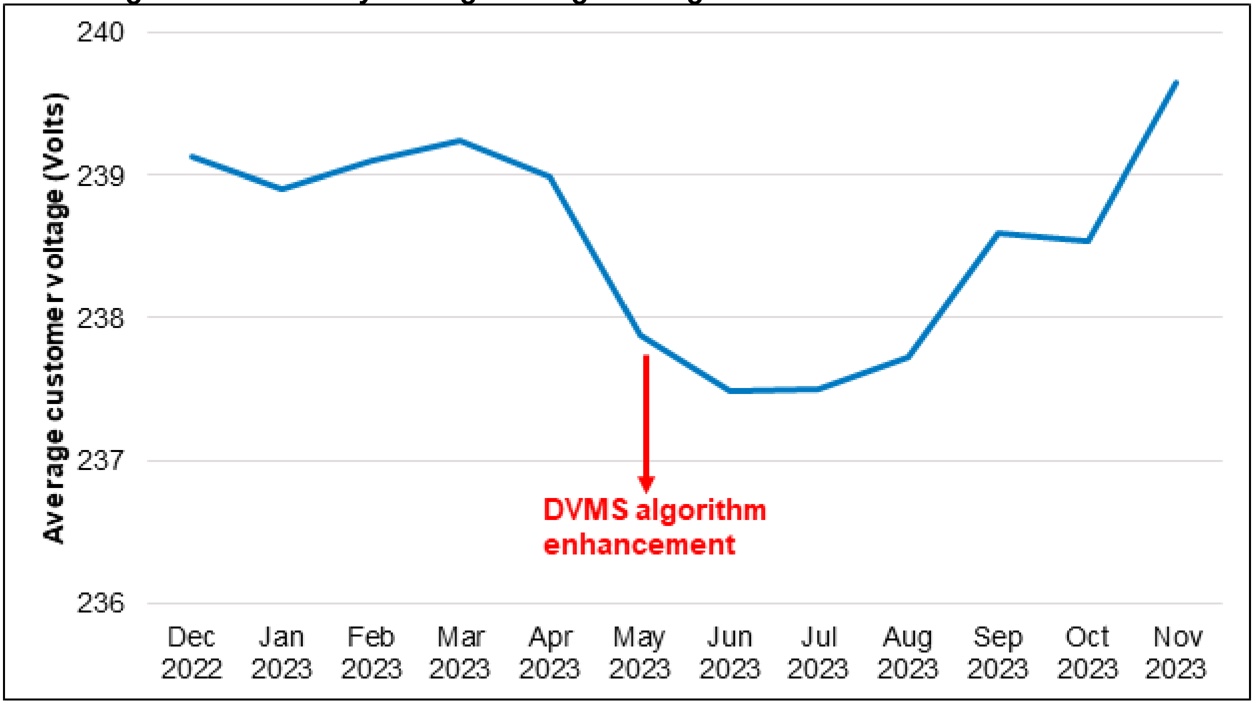


Figure 17.3 Monthly average voltage during 2022-23



As noted in Section 3.7, Powercor has undertaken numerous steps to improve customer voltage and have significantly increased works in 2023 through the solar enablement and DVMS programs. As a result, V99% performance has demonstrably improved year-on-year (i.e. comparison of June 2022 vs. June 2023). It should be noted there is seasonal and monthly variability to V99% performance and hence a year-on-year evaluation approach is taken to assess the impact of improvement works.

Moreover, the V1% performance of the Powercor networks remains high with some seasonal variations as shown in Figure 17.2.

Additionally, Solar PV inverter compliance to AS 4777 is a key priority area for Powercor to maintain voltage and improve Solar PV hosting capacity. On 1 October 2022, Powercor introduced a new commissioning sheet process to embed inverter compliance within our export approval system. Advanced DVMS analytics trialled throughout the period have allowed us to detect and verify compliance rates. Initial results suggest inverter compliance has improved significantly throughout the period. This will be a continued focus going forward with achieving near 100% PV installation compliance is crucial to maximising the amount of rooftop solar on the network while improving network wide functional voltage compliance.

Going forward, to improve and maintain voltage compliance Powercor will:

- invest in new systems, including the completion of implementing the DVMS and optimising its settings to manage network voltages in real time based on feedback from our AMI meters to optimise customer volts
- invest in the network, by continuing to identify works that improve customer voltage and deliver extra hosting capacity
- complete the works as part of the solar enablement program discussed in section 3.7.

17.2.3 AMI voltage data

Powercor is required to report AMI voltage information, as specified in Schedule 2 of the VEDCoP. Under the requirements of the Clause 19.4.1(e) of the VEDCoP (the Code) this planning report is required to include all of the information provided in Table 7 of the Code.

The Powercor dataset provided is the average of all customers connected to the relevant feeder and regulator section. The averages are calculated by taking the average across all customers for each 10 minute block within each day of the year. Those 10 minute averages are then grouped into the season and time period and averaged for the report.

Powercor's data can be found by accessing the link shown below and searching for LV voltage reports:

https://spaces.hightail.com/space/UaPnYI6yeV

For avoidance of any doubt, blanks in the data reflect changes in the network that cause a feeder to be out of service for an entire quarter. These changes include but are not limited to:

- establishment of a new zone substation or feeder
- decommissioning of an existing zone substation or feeder
- long duration (3 months) transfers while the network is being re-arranged and then returned to normal state.

17.2.4 Voltage performance at medium voltage network

Voltage variations at the medium voltage networks are required to maintain within the limit prescribed by the VEDCoP as stated in Section 17.2.1. The allowable limits for voltage variation are ±6% for urban networks and ±10% rural networks. Moreover, the limit for negative-sequence voltage unbalance is up to 2% for medium voltage networks as per the NER chapter 5 (Clause S5.1a.7). One or multiple power quality meters are used in each zone substations for observing the voltage performance in the medium voltage Powercor networks. The steady state voltage at all Powercor sites are within the upper (V99%) and lower (V1%) limts. Moreover, the voltage unbalances at the Powercor networks are within the limit.

17.2.5 Harmonics performance at medium voltage network

Voltage harmonic requirements are governed by the VEDCoP and the NER. The NER essentially requires that Powercor adheres to the 61000.3 series of Australian and New Zealand Standards.

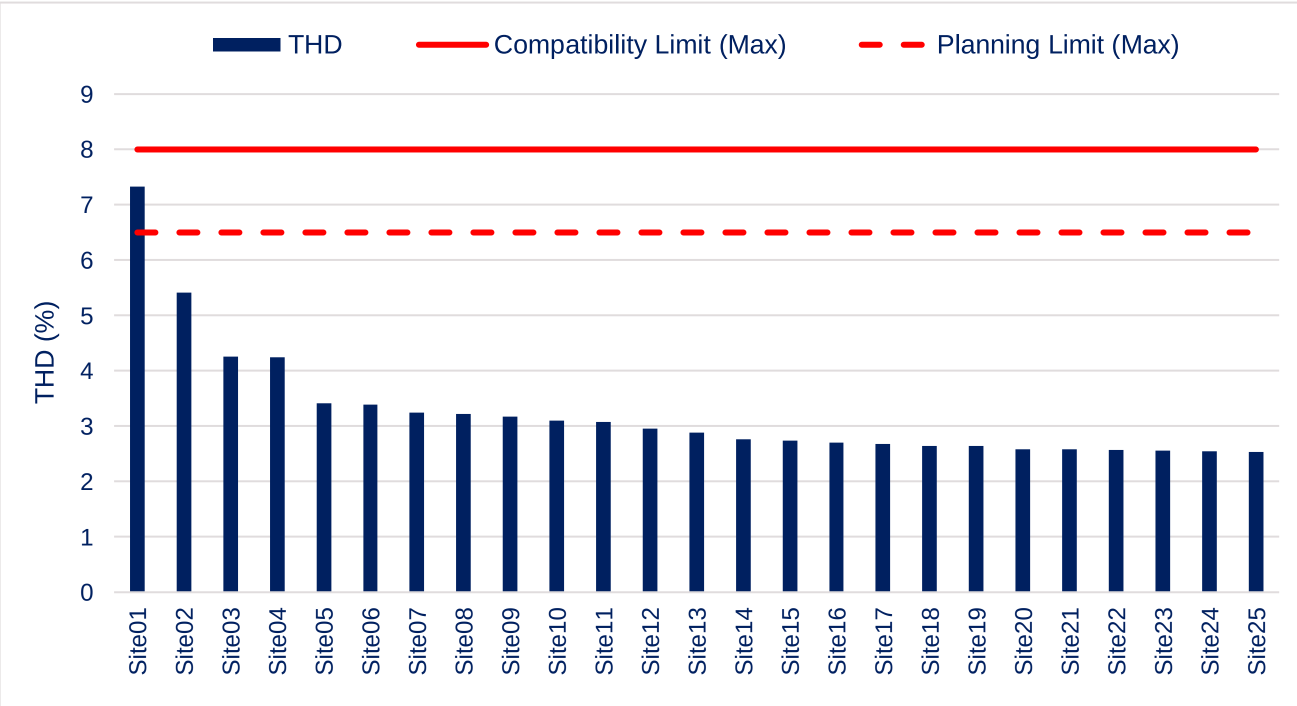
Powercor is required to ensure that the voltage harmonic levels at the point of common coupling (for example, the service pole nearest to a residential premises), with the levels specified in the following table from AS 61000.3.6.

Table 17.4 Voltage harmonic distortion limits

Odd harmonics non-multiple of 3		Odd harmonics multiple of 3		Even harmonics	
Harmonic order h	Harmonic voltage %	Harmonic order h	Harmonic voltage %	Harmonic order h	Harmonic voltage %
5	6	3	5	2	2
7	5	9	1,5	4	1
11	3,5	15	0,4	6	0,5
13	3	21	0,3	8	0,5
$17 \leq h \leq 49$	$2{,}27 \cdot \frac{17}{h} - 0{,}27$	$21 < h \leq 45$	0,2	$10 \leq h \leq 50$	$0{,}25 \cdot \frac{10}{h} + 0{,}25$
NOTE The compatibility level for the total harmonic distortion is THD = 8 %.					

Harmonics data for 25 worst performing sites are presented in Figure 17.6. It is clear from this figure that the total harmonics distortion (THD) at all Powercor sites are within the compatibility limit as well as the planning limit (planning limit is 6.5%, suggested by Australian standard AS 61000.3.6) except one site. The THD at one site is more than the planning limit, but it is still within the the compatibility limit.

Figure 17.6 Voltage harmonics for 25 worst performing sites (measured at the zone substation)



17.2.6 Flicker performance at medium voltage network

According to VEDCoP and NER, the voltage flicker is required to be limited as prescribed in Table 1 of Australian Standard AS/NZS 61000.3.7-2001 which is provided in Table 17.5. Flicker levels for 25 worst performing sites are provided in Figure 17.7 and Figure 17.8. These figures show that the both the short-term (Pst) and long-term (Plt) flicker for all Powercor medium voltage sites are within the limit except one site where Plt is slightly more than the allowable limit. Powercor is investigating the non-compliance site with the aim to resolve it.

Table 17.5 Compatibility levels for flicker in low and medium voltage systems

	Compatibility levels
P_{st}	1,0
P_{lt}	0,8

Figure 17.7 Short-term flicker for 25 worst performing sites (measured at the zone substation)

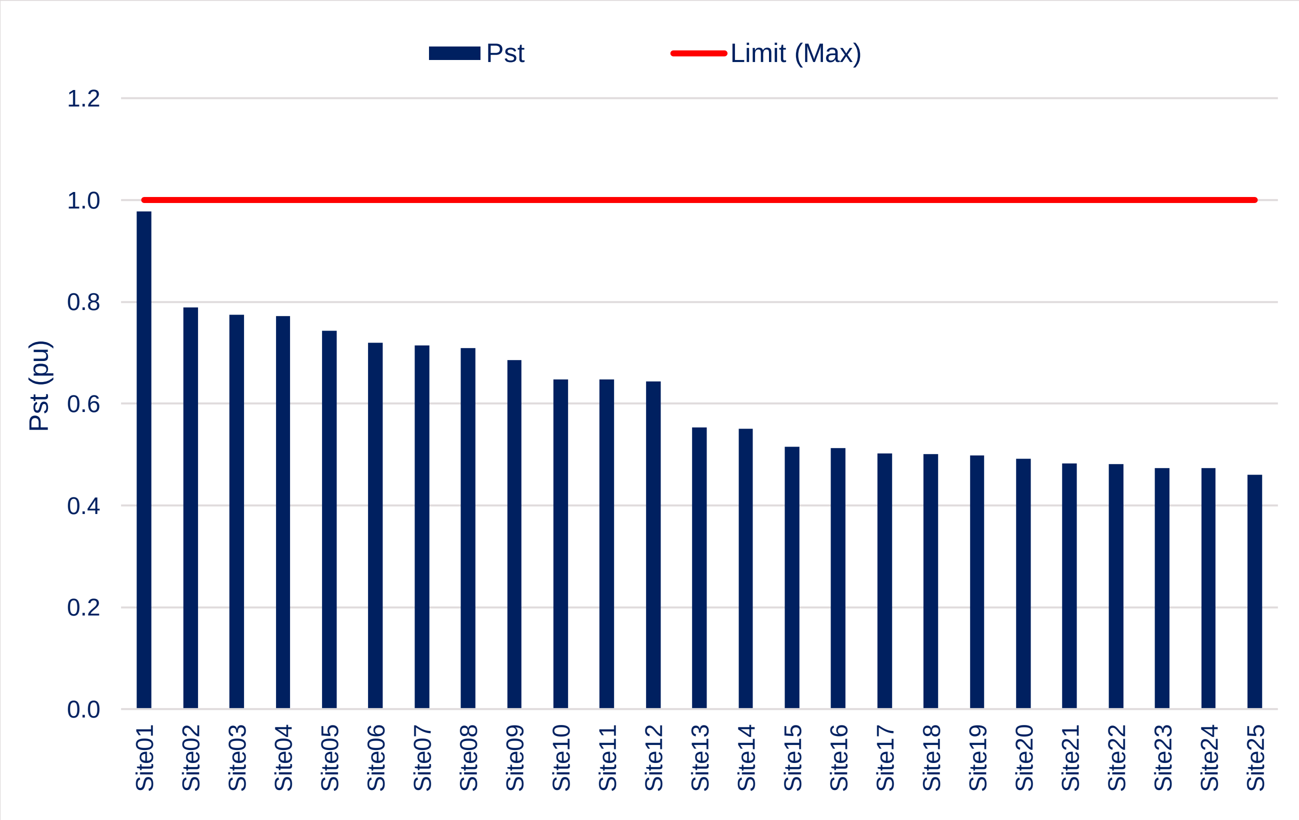
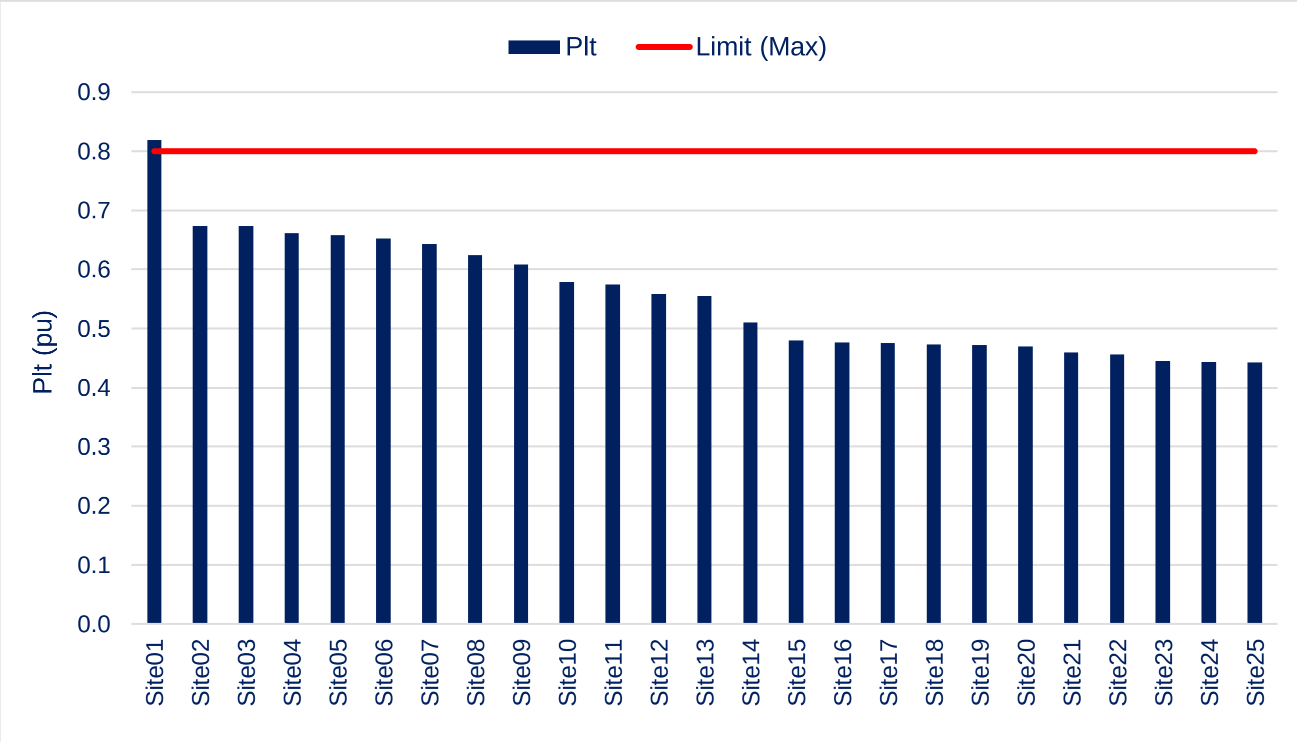


Figure 17.8 Long-term flicker for 25 worst performing sites (measured at the zone substation)



17.2.7 Maintaining power quality in Powercor networks

The solutions that Powercor may adopt include:

- installation of voltage regulators which will bring voltage levels at customer connection points within the applicable requirement
- the upgrade of existing distribution transformers, or the installation of new distribution transformers, to increase the ability of the network to meet customers' demand for electricity and improve voltage performance
- replacing small sized conductors with large conductors in order to improve the voltage performance, or
- installation of additional reactive power compensation, such as capacitor banks, to improve voltage performance.
- installation of harmonic filtering equipment to improve voltage harmonic performance.

Powercor may also identify issues with power quality following applications from potential "disturbing load" customers, such as an embedded generator or a large industrial customer, to connect to the network. System studies are carried out on a case-by-case basis to identify voltage, flicker or harmonic constraints relating to proposals, with recommendations for corrective action provided to the party seeking to connect.

18 Embedded Generation and Demand Management

This chapter sets out information on embedded generation as well as demand management activities during 2023 and over the forward planning period.

18.1 Embedded generation connections

The table below provides a quantitative summary of the connection enquiries under chapters 5 and 5A of the NER and applications to connect EG units received in 2023.

Table 18.1 Summary of embedded generation connections

Description	Quantity (>5 MW)
Connection enquires under 5.3A.5	11
Applications to connect received under 5.3A.9	2
The average time taken to complete application to connect in days	N/A
Description	**Quantity (>30 kW and <5 MW)**
Connection enquires under 5A.D.2	888
Applications to connect received under 5A.D.3	244

Powercor maintains and publishes a register of completed embedded generation projects under Clause 5.18B and Clause 5A.D.1A of the NER. The register can be found at the link below:

https://www.powercor.com.au/network-planning-and-projects/network-planning/#register_of_completed_embedded_generation_projects

Key issues to connect embedded generators to Powercor's network include:

- fault levels

- thermal capacity
- voltage fluctuations under various contingency scenarios
- harmonics and flicker issues for large-scale generator as a result of limitations of power quality allocations at terminal stations and consequential allocations to wind and solar farms leading to tight design criteria.

18.2 Non-network options and actions

Powercor actively seeks opportunities to promote non-network alternatives for both general and project-specific purposes. Up to summer 2023/24 the following details some of Powercor activities:

- Powercor had communicated with providers of demand management and embedded generation services to explore potential non-network options
- Powercor was involved with the development of a number of embedded generation projects at various stages. Powercor has recently commissioned 8 MW of embedded generation in 2023, making a total of 1392 MW of installed capacity. In addition, there are 18 approved projects totalling 485 MW in development
- Powercor monitors industry developments and engages with providers of demand management and smart network technologies
- In 2023, Powercor continued with a feasibility study, in partnership with 12 community energy groups and local councils, CitiPower and United Energy, and supported by the Department of Energy, Environment and Climate Action (DEECA) through the Neighbourhood Battery Initiative (NBI) program. This study aims to identify opportunities for neighbourhood batteries and develop supporting information to assist community groups who are looking to explore a neighbourhood battery project.
- The feasibility study identified that there was an interest from community energy groups, local councils, research organisations and the DEECA in having a greater understanding of their local distribution network. A mapping tool is being developed to demonstrate the locations and scale of network opportunities which may be addressed by non-network solutions.

Over the forward planning period, Powercor intends to continue to consider demand side options via its Demand Side Engagement Strategy.

18.3 Battery Programs

Powercor is supporting network owned and third party owned community batteries. These batteries will support increased DER hosting capacity as well as provide opportunities for third party investment into assets that support the networks as a non-network solution.

18.3.1 Tarneit Community Battery

In 2021, Powercor initiated the Tarneit Community Battery project. This project has arisen from Powercor's successful “Tarneit Neighbourhood Battery Initiative” application in 2021. The project is supported by (DEECA).

As a result the Tarneit Community Battery, a 120KW/360KWh ground-mount three phase battery has been installed to support a network-constrained Tarneit distribution substation at *Parkway-Gleneagles* and the associated LV circuit works

The project intends to demonstrate value stacking of benefit streams and build capability to mitigate network constraints while also developing a future economic business model that leverages market services revenue and demonstrate how batteries can support greater residential solar output.

The project was completed in early 2023 and was jointly announced with the Victorian Minister for Energy, Environment and Climate Action.

18.3.2 Maldon Community Battery

Powercor has successfully secured a $500,000 grant from Federal Government under the Community Batteries for Household Solar program. For a community battery at Maldon.

The Maldon Community Battery is provisionally a 90kW/270kWh ground-mounted system to address local network constraint and enable additional 112 MWh of solar exports each year in the local area.

Construction is expected to begin next year, with completion planned in early 2025.

18.4 Demand side engagement strategy and register

Powercor has a Demand Side Engagement Strategy designed to assist non-network providers in understanding Powercor's framework and processes for assessing demand management options. It also details the consultation process with non-network providers. Further information regarding the strategy and processes is available from:

https://www.powercor.com.au/network-planning-and-projects/network-planning/#demand_side_engagement_strategy

Powercor has also established its Demand Side Engagement Interested Parties Register in mid-2013. It currently allows interested parties to provide contact details and email address data, but will be enhanced in the near future to become an online form portal. To register as a Demand Management Interested Party, please email the following:

- DMInterestedParties@powercor.com.au

In 2023, no formal submissions from non-network providers were received.

19 Information Technology and Communication Systems

This chapter discusses the investments we have undertaken in 2023, or plan to undertake over the forward planning period 2024-2028, relating to information technology (**IT**) and communications systems.

19.1 Security Program

We continue to deliver on our commitments in our Cybersecurity strategy to ensure our network and customers remain protected. Our program of work continues to focus investments in Cybersecurity governance, risk and assurance management, security operations and technical capabilities to address the evolving threat landscape and regulatory requirements under the Security of Critical Infrastructure Act (SOCI) 2018. Our focus remains on building and maintaining a Cybersecurity function that can proactively prevent, detect, respond to, and recover from Cybersecurity threats that have the potential to disrupt the operation of the distribution network and our services.

Through our Cybersecurity strategy, we have delivered security uplift programs to our network/communications and identity platforms. Our current in-flight projects will progress into 2024 and deliver on uplifting our web security, identity management, operational technology (OT), and training and awareness programs. Our current cyber security strategy will be fully delivered by 2025 and we have begun planning for our next phase of the strategy. We have met all current requirements under the SOCI act, including the Risk Management Program (RMP) Cyber and Information Security Hazard rules. We remain on target to meet additional requirements in 2024.

As part of our cybersecurity assurance program, we also conduct a series of formal and applied assessments that ensure the effectiveness of our controls and procedures. These include formal audits, penetration testing and simulated responses to a broad range of threat scenarios.

We will continue to align our security strategy and initiatives to ensure compliance with the SOCI act, and relevant industry standards such as Australian Energy Sector Cyber Security Framework (AESCSF), and authorities such as Australian Signals Directorate (ASD) / Australian Cyber Security Centre (ACSC) to ensure that controls implemented are consistent with recognised Australian and international best practices.

19.2 Currency

We routinely undertake system currency upgrades across our IT systems to reflect vendor software release life cycles and support agreements. These refresh cycles are necessary to ensure system performance and reliability are maintained, and that the functional and technical aspects of our systems remain current.

In 2023, we continued the following upgrades:

- Customer information system (CIS/OV) upgrade – this included upgrading the surrounding components of our customer information system, for example, database, operating system, to ensure currency
- Distribution Management System (DMS) upgrade – this included upgrading our current DMS to improve resilience and currency and onto the latest product version PowerOn Advantage – this upgrade went live in September 2023
- Telephony refresh – this includes an upgrade of our existing system which is nearing its end of life to deliver a more resilient platform to avoid the risk of incidents to the system.

In 2023 we also undertook following upgrades:

- Field Collection System (FCS) – this upgrade was to support collection of 5 minute data from meters which necessitated various component changes to servers and moving away from the old handheld to a tablet, which will support the Itron Mobile applications

During the forward planned period for this DAPR we will continue to maintain the currency of our systems. Upgrades expected in the forward planning period include:

- Outage Management System (OMS) upgrade – this includes migrating the current OMS off PowerOn Restore to PowerOn Advantage, mapping the LV model for improved safety outcomes and uplifting LV/HV data quality – this initiative has just completed it's detailed design phase
- Market system upgrade – uplift capability of market systems applications, which support market transitions and data to be provided to the market
- TrendSCADA (Historian) replacement – this includes replacement of the current legacy historian (Operational Technology data store) application, used to support planning of the network, with an improved platform called OSI Pi to address IT security and reliability risks, and uplift business functionality. The project is inflight, due to go-live in late 2024
- Geospatial Information System (GIS) upgrade – this will include a major upgrade targeted to commence in 2027
- ADMS Upgrade – this upgrade will ensure that we maintain resilience and currency of our ADMS so that we can continue to manage the network – targeted to commence in 2028

19.3 Compliance

We are focused on ensuring that, as regulated businesses, our IT systems support all regulatory, statutory, market and legal requirements for operating in the National Electricity Market (NEM). These obligations are regularly amended by various government bodies and regulators to reflect the changing energy market. We ensure compliance through prudent investment in systems, data, processes and analytics that provide the requisite functionality and reporting capability to efficiently comply with statutory and regulatory obligations.

In 2023 we completed Phase 3 of the five-minute settlement program which included:

- bringing the operating environments up to date to meet security standards and benchmarks, tuning and performance improvements and enhancements of system processes identified through defects and problem tickets, resulting from previous 5MS and GS go-live activities.
- At Powercor, this initiative covers changes and enhancements to the key market systems including MTS/ IEE as well as key supporting revenue management functionality.

This year we also updated our key market systems to:

- Deliver three new trial tariffs designed in consultation with external stakeholders and the Victorian Government to support the rapidly changing energy market
- Update the structure of B2B transactions in line with the B2B 3.8 procedure changes to improve communication between market participants
- Enhanced our systems to support two sets of Industry Change Forms (ICF) arising from market participants and AEMO identifying market processes that require correction or improvement,
- Minor updates to systems resulting from the Consumer Data Rights reform.

In the forward DAPR planning period, we will continue to implement compliance projects as these arise. We will also continue to amend our system and data controls to ensure customer, employee and asset data remains hosted in Australia.

19.4 Infrastructure

We have an increasing need to store and recall data, as well as support applications, processes and functions across our IT systems. To support this, we must ensure our IT infrastructure remains technically current, meets relevant security requirements and meets our service level requirements to our customers and energy markets.

During 2023 we established new applications, supported by cloud-hosted infrastructure, while retaining our existing infrastructure on premise.

This included:

- Deployed additional storage and data backup infrastructure to accommodate growing data volumes. The additional storage was delivered via an upgrade to the new storage infrastructure deployed in 2022.
- Deployed a new backup solution for large sized databases that provides a tenfold reduction in backup and restore times compared to the previous solution.
- Refreshed critical network infrastructure to ensure we were on a supportable solution, have the capacity to accommodate increasing network traffic volumes and provide the ability to protect our devices against cyber-attacks.

- Refreshed critical network security “firewall” devices to ensure we were on a fully supported solution, and consolidated onto a single vendor to enhance our security against cyber threats.
- Upgraded server infrastructure to ensure that we are running on a modern supportable platform, have the capacity to accommodate increasing application demands and ensure that our servers are able to have security patches applied.
- Deployed new meeting room technology to effectively support the post COVID mix of remote and on premise staff.

During the forward planning period for this DAPR, we will continue to upgrade our underlying infrastructure to support our IT environments to maintain capacity, performance and availability to ensure business continuity capability. We will also continue our program of gradually migrating some of our existing on-premise IT infrastructure to the cloud. We have also initiated a program to consolidate the United Energy IT infrastructure into the CitiPower and Powercor data centres to achieve efficiencies and cost savings for both organisations.

19.5 Customer Enablement

Customer enablement incorporates our response to ongoing changes and demands from our customers for greater access and greater choice in their distribution services.

Faults communication was a focus of 2023 where system enhancements were introduced to reduce unnecessary ETR notifications received by customers, to issue alternative ‘Restore’ messages where customers have a defect and improve the display of outage information on the corporate website. In addition to system changes, we have procured a second on-the-ground vehicle, Vehicle for Engagement Response and Assistance (VERA), ready for deployment to support vulnerable customers and communities during prolonged outages.

Further enhancements to our digital offerings enabled customers to upload photos of faults or issues with our assets, allowed customers to submit network data requests electronically and myEnergy portal subscribers to see a display of planned outage information for their property.

The Customer strategy refresh identified 10 key focus areas for the remainder of the current regulatory period, outlining 31 initiatives and 96 sub-initiatives beneath these focus areas that, when implemented, will help deliver on our strategic imperatives. We have commenced work on priority initiatives, which will be implemented in 2024, these include:

- An ‘Uber’ faults pilot experience to allow customers and employees to view progress of crews travelling to, and working on, faults. This will provide greater transparency and accuracy of faults restoration to customers and employees.
- A Contact Centre of the future where customers are offered their channel of choice to engage with the business, customer service agents can work across a range of enquiry types and further benefits are derived from the speech analytics platform informing improvements in call handling and proactive identification of issues.
- Outage communication enhancements making use of network analytics to identify customers still off supply resulting in accurate communication and faster restoration; further improvements in faults and planned outage notifications providing customers more timely; and outage map improvements providing customers with more information about outages.

- Customer service online training, for new and existing employees, emphasising a culture where employees provide the customer with options, feel empowered to make decisions and have empathy for the customer's circumstances. Training will also focus on enhancing employee phone, face to face and written communication skills, particularly when dealing with difficult or angry customers.

19.6 Becoming a More Digital Network

Australia is supporting the uptake of local low carbon technologies such as roof top solar, home and community batteries and electric vehicles. We also want to support greater customer choice and provide the flexibility for greater independence in customers' energy usage decisions.

2022 also saw the implementation of a community battery solution which developed a third party facing interface to enable market participants access to network assets to participate in market services such as frequency control ancillary services (FCAS) and energy arbitrage.

Through 2023 we have progressed a number of initiatives including:

- Enhancements to the community battery solution, to enable more community batteries to connect to our network, including the Tarneit Community Battery
- Network Hosting Capacity modelling, used to produce granular long-term forecasts on network hosting capacity, critical for identifying constraints and informing targeted and well-timed network investment.
- Development of dynamic LV control capability required to meet the Emergency Backstop Response compliance mandate. This capability enables us to remotely ramp down or switch off customers with solar during a minimum demand event, avoiding wide-scale power outages.
- Enhancements to existing large-scale customer generator controls, to enable control of large scale customer battery solutions. This dynamic control capability removes many of the cost barriers (network augmentation) to connecting large generation solutions, further supporting renewable energy growth on our network.
- Expansion of the Community Portal mapping tool, which visualises network data to community groups and entities to enable improved visibility of suitable areas for rewable energy solutions

Part of the digital revolution is being able to provide more information on how the electricity network is performing in more usable formats.

Over the forward planning period we will continue the Digital Network journey by focusing on enhancing asset data models, network granularity and forecasting, data quality, and analytics to further improve how we manage the network. The aim is to develop a "Digital Twin" capability that will support the changing role of the distribution network. Specific initiatives include:

- Development of Dynamic Operating Envelope (DOE) methodologies based on AMI and other sensor data to determine how best to implement DOEs and guide investment requirement for ubiquitous integration in the future

- Trial an implementation of DOEs for commercial customers and residential customers to improve overall solar hosting capacities, via a Flexible Exports Trial (currently in development, due to commence in H1 2024)
- Implement a first generation operational forecasting capability along with a complete digital network model from Terminal Station (transmission connection) to the customer connection
- Continued expansion of the visualisation of network performance and constraints to more community groups and entities, to enable improved visibility of suitable areas for renewable energy solutions
- Building on network constraint visualisation, trial a flexibility marketplace (procurement platform) implementation to test market viability for non-network solutions (due to go-live in H1 2024)
- Development of further minimum demand response mechanisms, including AMI load shedding, which will seek to identify and cluster exporting customers to curtail export during a minimum demand event. This will enable us to avoid shedding feeders as a first resort (which takes load customers off supply), improving customer and network outcomes.
- Development of sophisticated AMI forecasting capability, to improve LV management outcomes

19.7 Other Communication System Investments

To facilitate and maintain the protection, control and supervision of the network, we continue investment in Supervisory Control and Data Acquisition (**SCADA**) and the requisite network communication media and control equipment needed to achieve this. This is used to monitor and control the distribution network assets, including zone substations, Customer distribution substations and feeders.

In 2023 we have completed works on the following:-

- Replacement of 3 aging radio systems to with improved reliability, robustness as well as real time performance monitoring and reporting
- Commenced scoping the introduction of MPLS technology to ease capacity issues on some sections of Powercor’s optical fibre network
- Enhancing the physical security of our communications assets by introducing a state-of-the-art locking system.
- Retrofitting of aging “Conitel” (VF) over Supervisory cable-based signalling network control equipment in key CitiPower Distribution Substations (DSS) with modern DNP3 over Ethernet carried on Optic Fibre
- Continued to replace 3G devices with new 4G technology introducing centralised and remote configuration management and real time performance monitoring and reporting. The Powercor replacement program will be more than 75% complete at the end of 2023.

Over the forward planning period for this DAPR, our investment in SCADA will continue to increase, consistent with the growth and complexity of the network. Our SCADA expenditure will continue to modernise the communications network to support adequate capability and capacity by installing larger systems.

Old communications systems will continue to be retired and replaced with newer up-to-date systems, addressing technical obsolescence

- where the manufacturer no longer supports the equipment which can no longer be upgraded and
- there is a reduced pool of skilled workers able to maintain the system.

We continue to modernise systems that are dependent on communications systems such as remote communications devices presently using the Telstra 3G Cellular network, such as Automatic Circuit Reclosers (**ACR**s), SWER ACRs, Gas Switches, Regulators, Cap Balancing Units and remote controlled HV switches, to 4G and 5G. Also, we will be investing in MPLS technology to increase capacity to meet the future network needs.

20 Advanced Metering Infrastructure Benefits

This chapter discusses our use of advanced metering infrastructure (**AMI**) technology and how information generated by AMI is being used to better support life support customers, guide network planning and demand side response initiatives, and support network reliability initiatives. AMI technology is also being leveraged in our digital network initiatives presented in section 19.6 above.

20.1 Life support customers

We are using our AMI technology to service and support our vulnerable customers more effectively, allowing us to keep our communities safe.

We are keeping our customers and communities safe through being alerted to life support customers off supply more quickly through our AMI meters across our network. Our systems alert us if the supply to an AMI meter associated with a life support customer fails enabling us to more quickly resolve supply to the customer. This is key to our response planning for customers off-supply and allows us to understand the criticality of the disruption.

Our AMI technology also assists us in rotating load in emergencies. By rotating load, we can share energy among our customers in times of emergency. As such, we can prioritise life-support customers in these cases to ensure their power remains on.

We plan to continue to leverage AMI data and services to develop further benefits for our customers, including life support customers, over the forward planning period. An example of an initiative we are proposing under our Digital Network program which is reliant on our AMI includes more accurate mapping of customers to supplying LV transformers to help keep more life support customers connected during emergency load shedding and provide more accurate communications to customers of planned outages.

20.2 Network planning and demand side response

AMI technology has been critical in allowing us to innovate in the way we operate the network and deliver effective customer service. Visibility of the low voltage (**LV**) network has improved customer outcomes by lowering prices through more efficient network management, improved network safety and reliability outcomes and improved responsiveness to customer needs.

Our AMI meters provide us with the ability to improve safety by identifying neutral faults at customer premises. Our systems alert us if the supply to an AMI meter has a neutral fault enabling us to more quickly resolve it. The system identifies unsafe situations as they develop, so corrective action can be initiated immediately. This is key for maintaining safety for our network and our customers.

Using Victorian AMI specification also allows us to manage voltages and prevent load shedding and blackouts on peak demand days.

Further the Victorian AMI is vital for enabling growth in distributed energy resources (**DER**) such as rooftop solar, batteries and electric vehicles. AMI provides us with the information to manage the network and accommodate the dynamic and less predictable energy flows that result from the increasing uptake of DER technologies by Victorians. We also use our AMI data for more accurate spatial demand forecasting, ensuring we optimise timing of network augmentation. Information from our AMI meters also assist us with detecting of customer with solar connections that are not registered as solar customers and/or are exporting more than they are contracted to export.

Our AMI technology is also an essential input into our Digital Network program which will enable more demand response initiatives through our proposed DER management system as well as enable us to accommodate more solar with the existing network capacity. We plan to continue to leverage AMI data and services to develop new benefits for customers over our DAPR forward planning period. The following are some examples of initiatives we are proposing under our Digital Network program which are reliant on our AMI:

- Promoting electric vehicle uptake – monitoring and optimising EV charging to understand and estimate the impact of increasing demand on the distribution network resulting from EV penetration
- Optimising load control of customer appliances – optimising existing hot water load control and enabling new load control programs (e.g. air conditioners and pool pumps), including through utilising excess solar in the middle of the day
- Enhancing cost reflective incentives – analysing AMI interval data to construct more effective demand management incentives and time-of-use tariffs to reduce peak demand. This would improve overall utilisation of the distribution network, resulting in lower prices
- Detecting electricity theft – identifying sites with bypass connections and reduction of theft, as well as identifying unregistered DER
- Proactively managing asset failures—resulting in fewer fire-starts and avoided replacement expenditure
- Avoiding fuse operations—improving phase balancing, which will allow greater asset utilisation (and therefore reduce augmentation) as well as avoiding replacement expenditure from blown fuses
- Minimum demand management – by shifting loads such as hot water connected to the meter, we are able to help manage minimum demand that is becoming more evident as renewable energies become more prevalent.

20.3 Network reliability

AMI information is being used to support our network reliability measures. We have shorter outages due to earlier identification of faults and more efficient restoration. This is because AMI meters give us almost instant notification of customers going off supply. We receive immediate notification of outages from the AMI meter which feeds into our outage management systems and automatically schedules and dispatches field crew to restore supply.

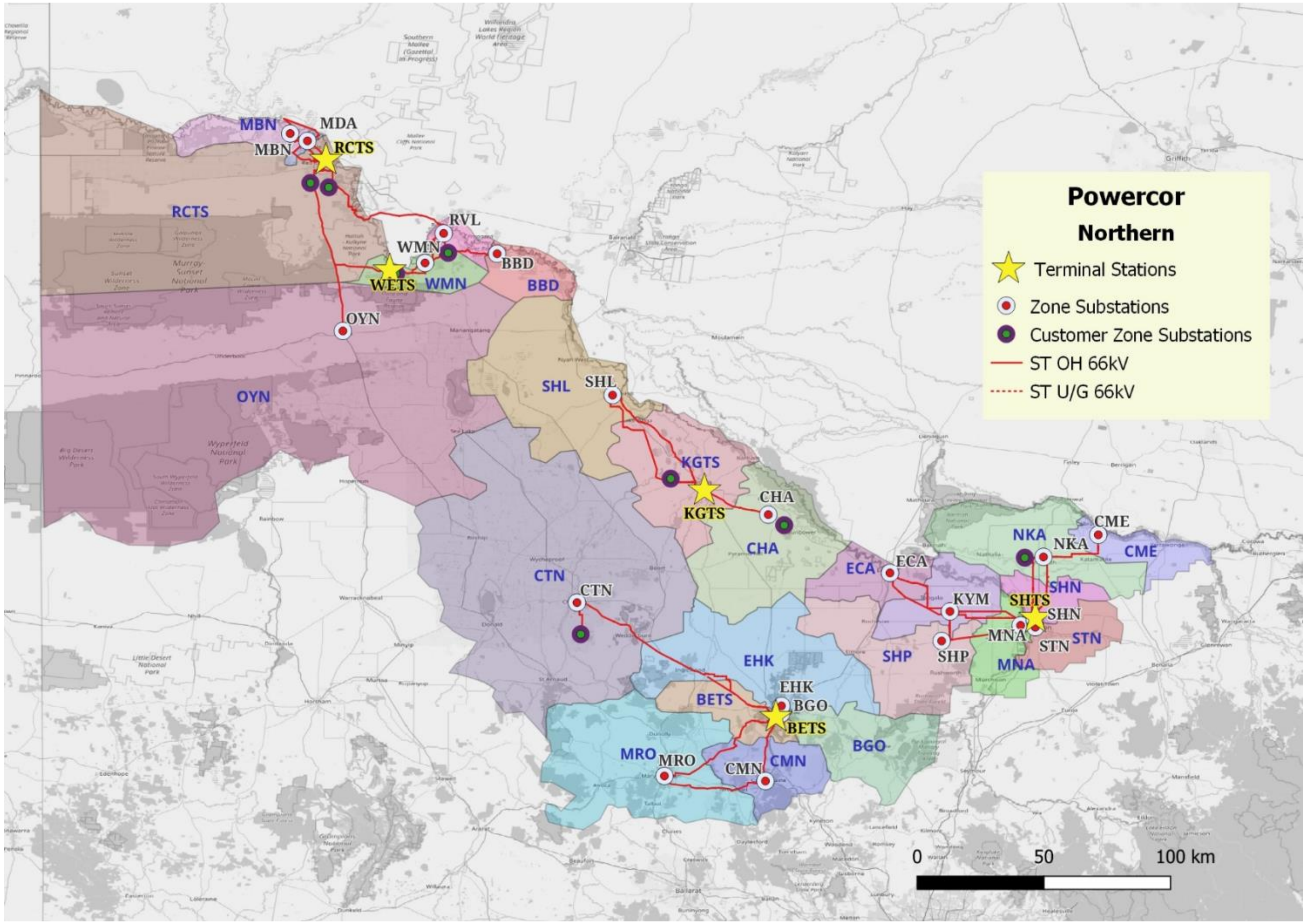
AMI meters also allow us to monitor basic power quality levels at individual customer premises. We have developed query and reporting tools to aggregate the data into meaningful sets of information and provide exception reporting to better manage the quality of supply to customers such as steady-state voltages, voltage sags and swells and phasing information. We have enhanced the AMI architecture to provide an engineering user interface for customer power quality information and to facilitate investigations into poor power quality performance. The interfaces also identify phase unbalance and other power quality performance issues (such as loose connections) to facilitate identifying the most appropriate mitigation solutions.

Our AMI technology also allows for supply capacity control enabling us to more effectively target load shedding to minimise supply impacts.

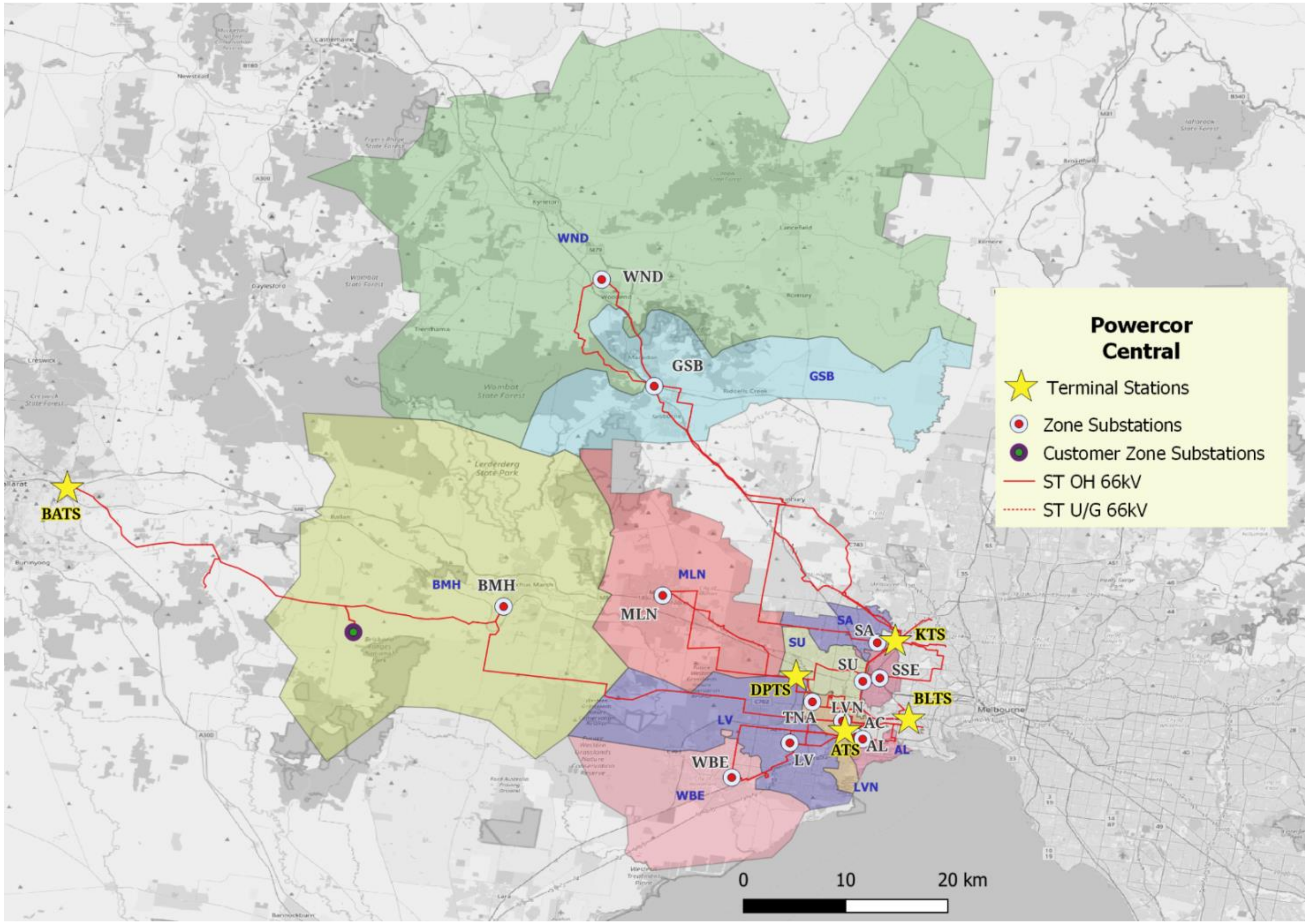
There is also improved quality of information and customer services during outages. We have developed an Interactive Voice Response service and SMS service which automatically advises customers of outages identified in a timely way through the last gasp AMI function. This has contributed to high levels of customer satisfaction with the service received. The quality of supply of information throughout the network is also enabling better network load profiling, identification of safety risks and voltage management.

Appendix A Maps

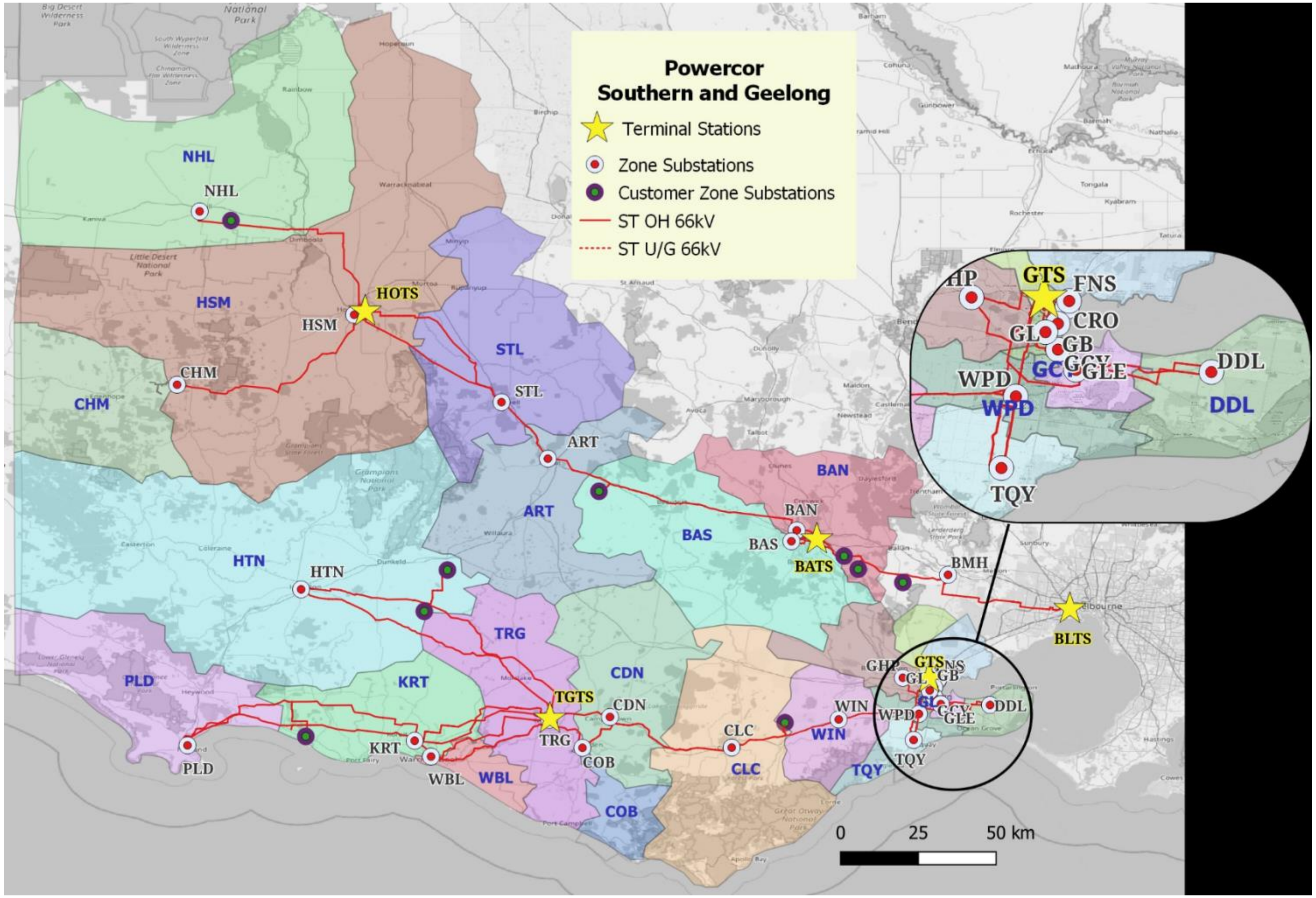
A.1. Northern area zone substation and sub-transmission lines



A.2. Central area zone substations and sub-transmission lines

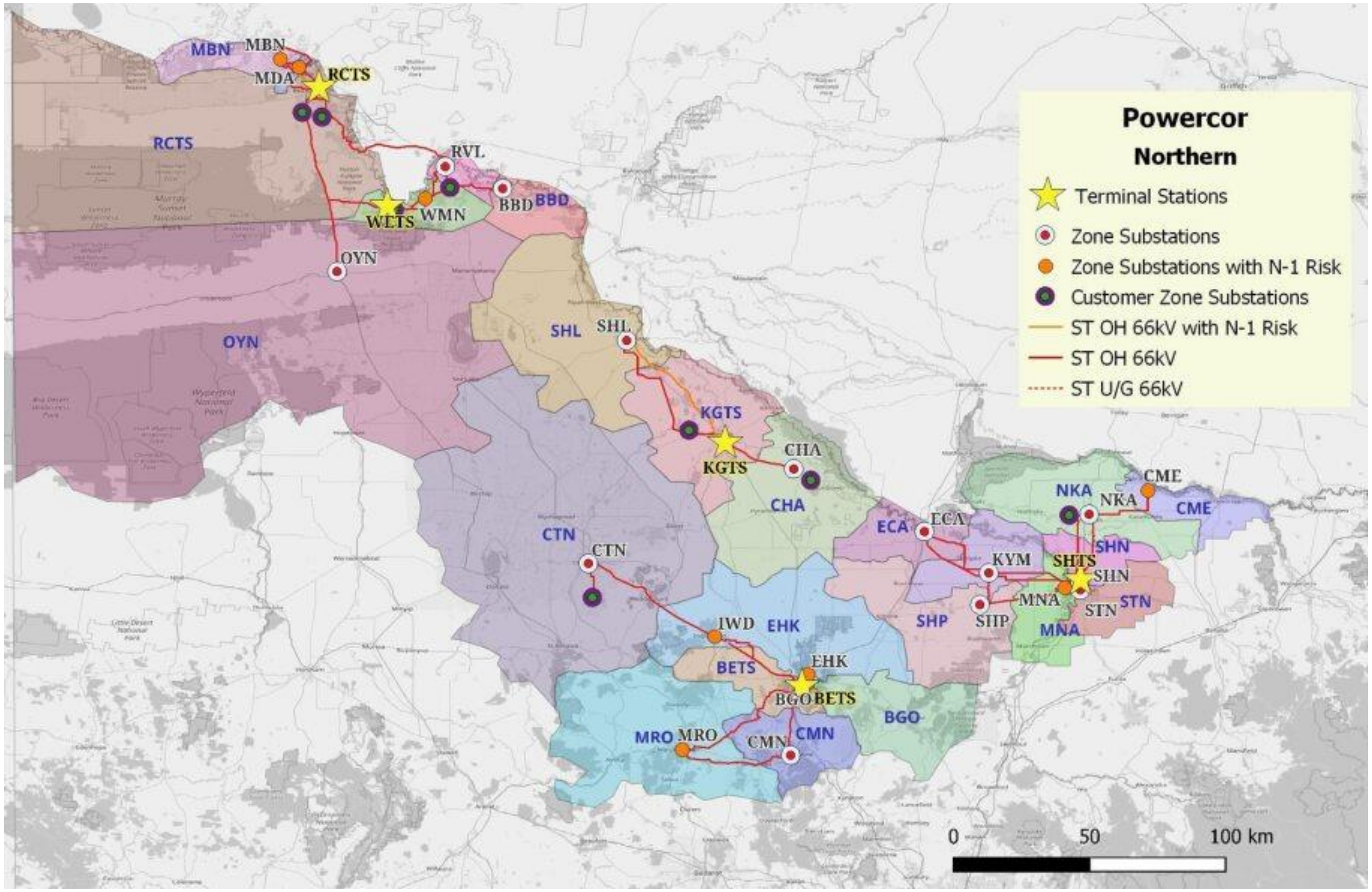


A.3. Southern area zone substations and sub-transmission lines

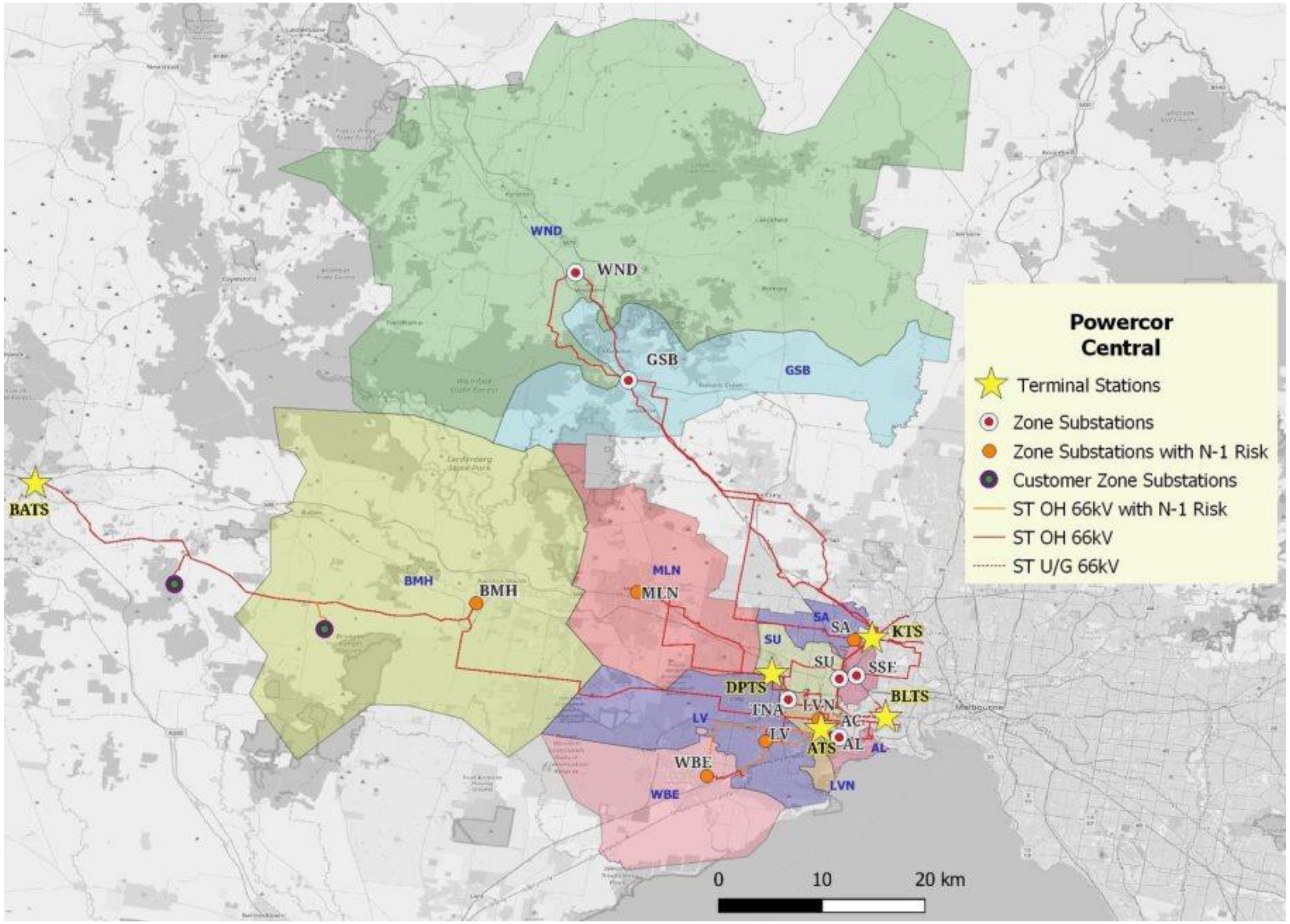


Appendix B Maps with forecast system limitations

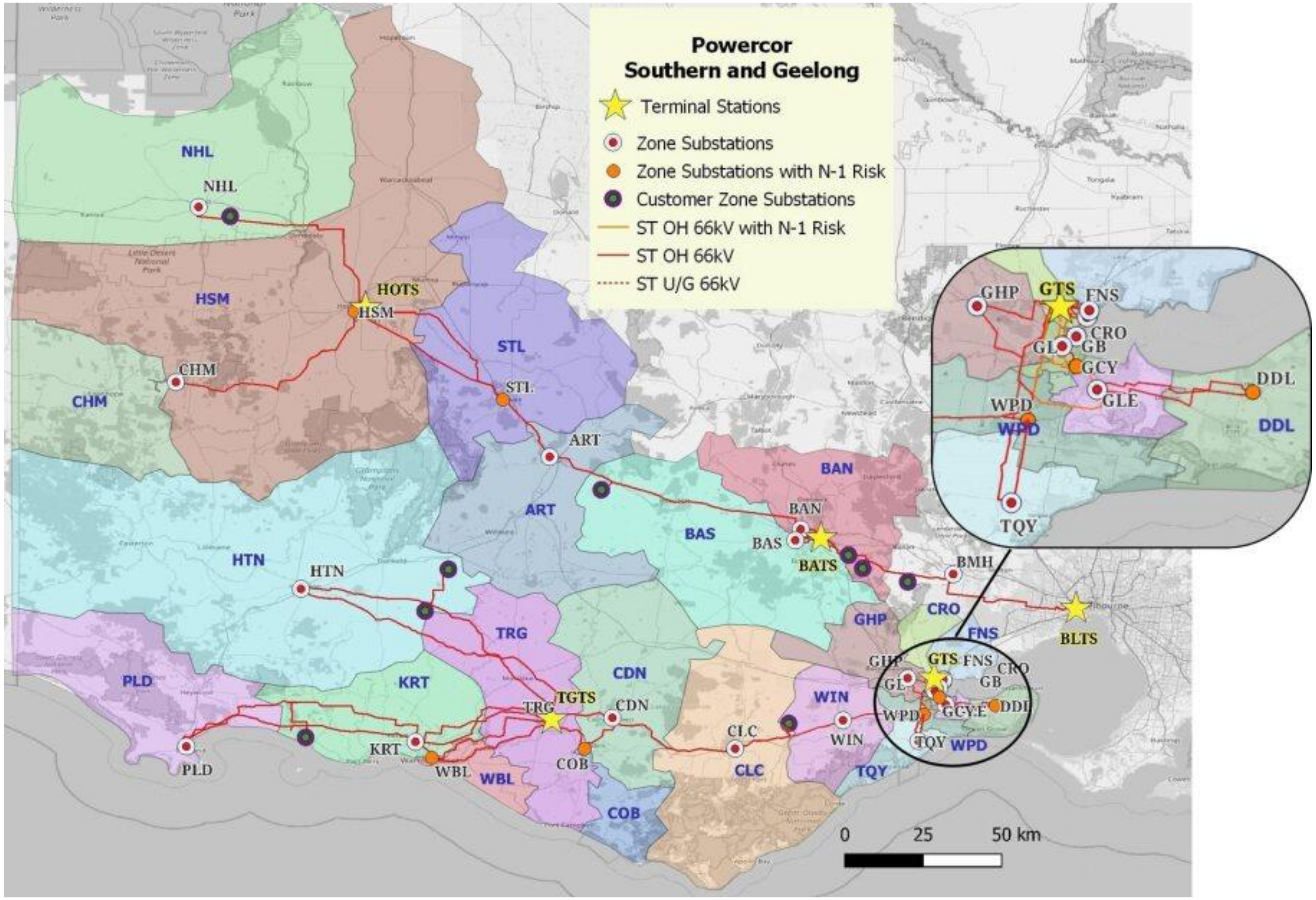
B.1. Northern area zone substation and sub-transmission lines with forecast system limitation



B.2. Central area zone substations and sub-transmission lines with forecast system limitation

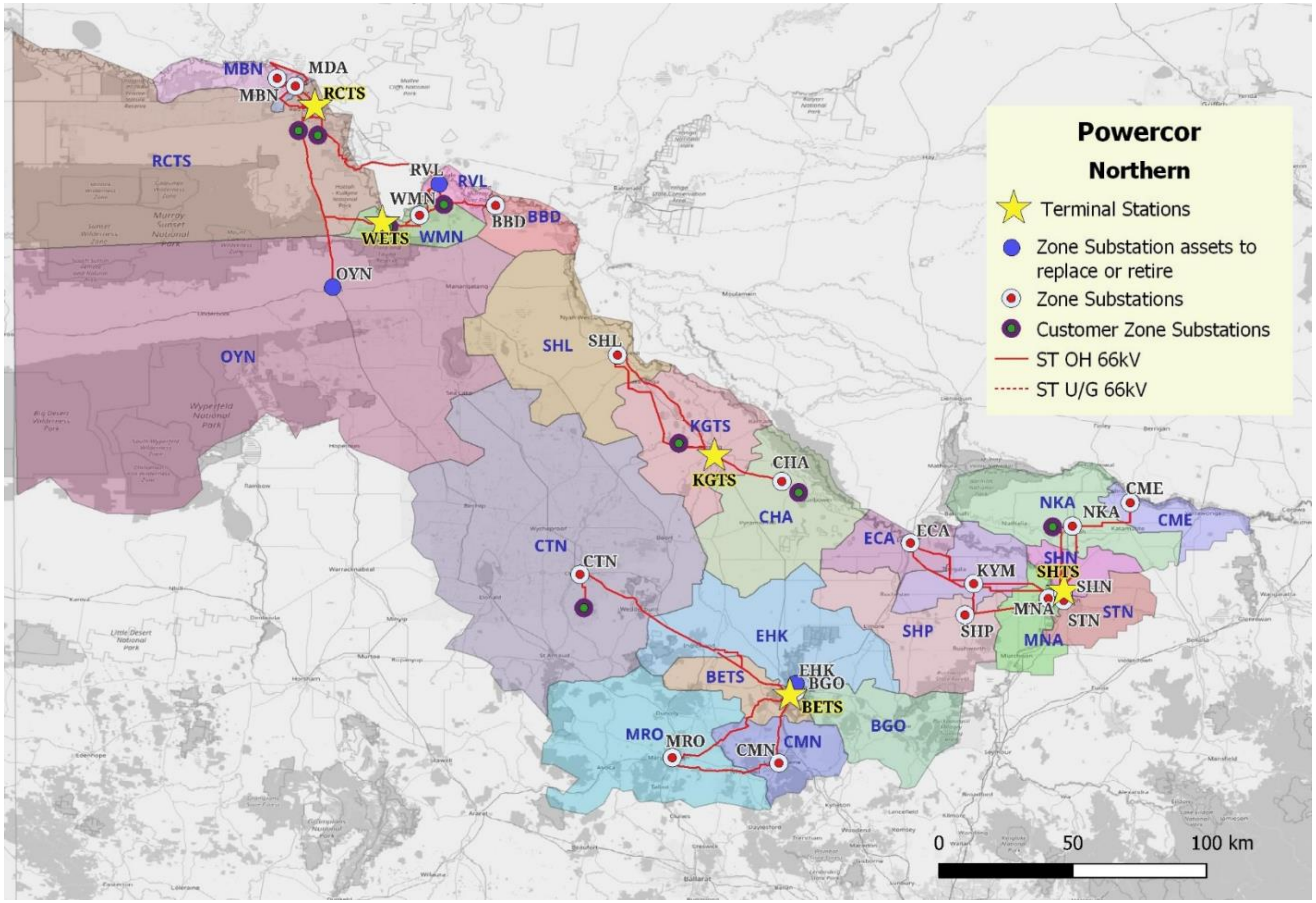


B.3. Southern area zone substations and sub-transmission lines with forecast system limitation

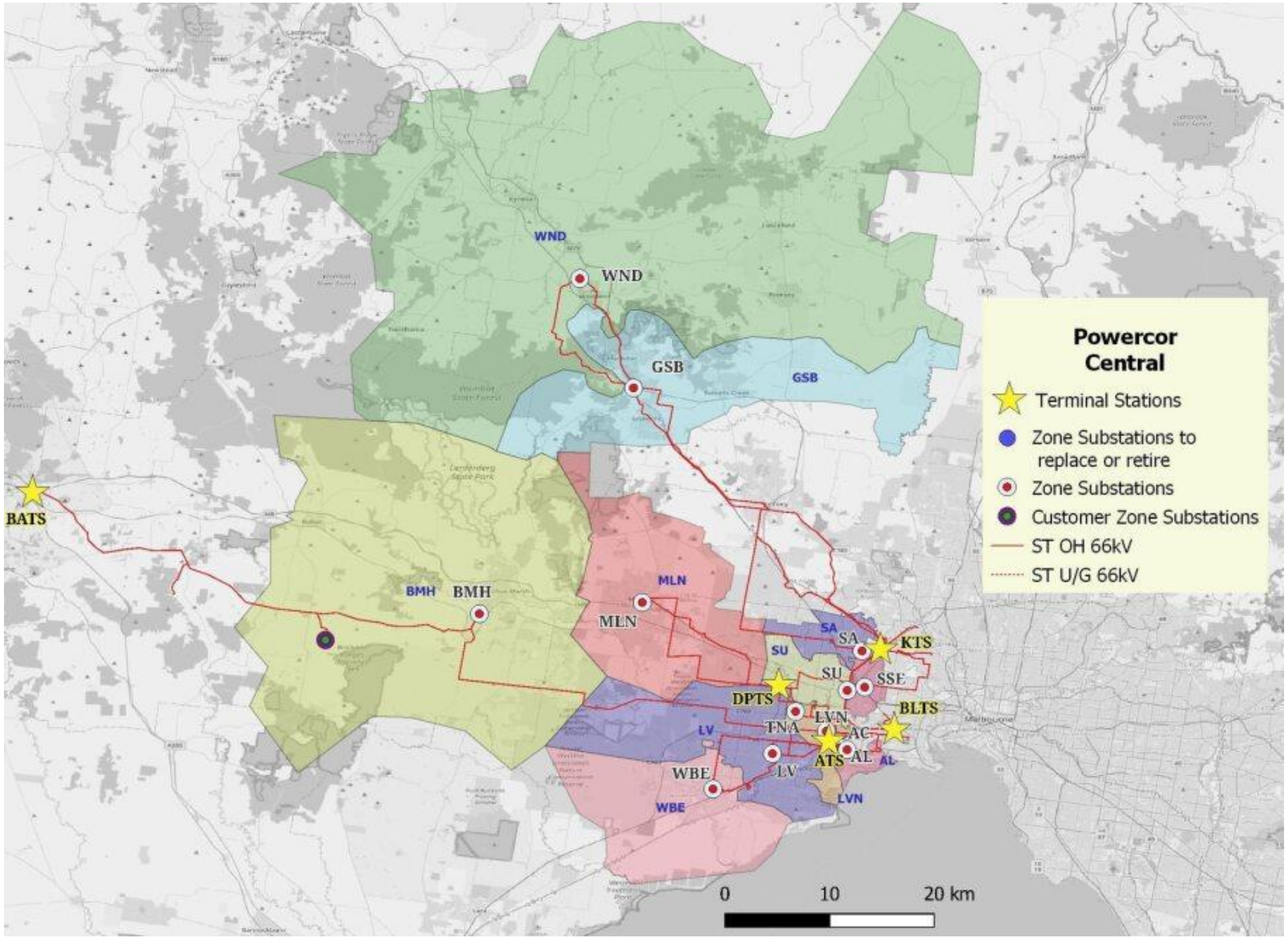


Appendix C Maps with asset to be replaced or retired

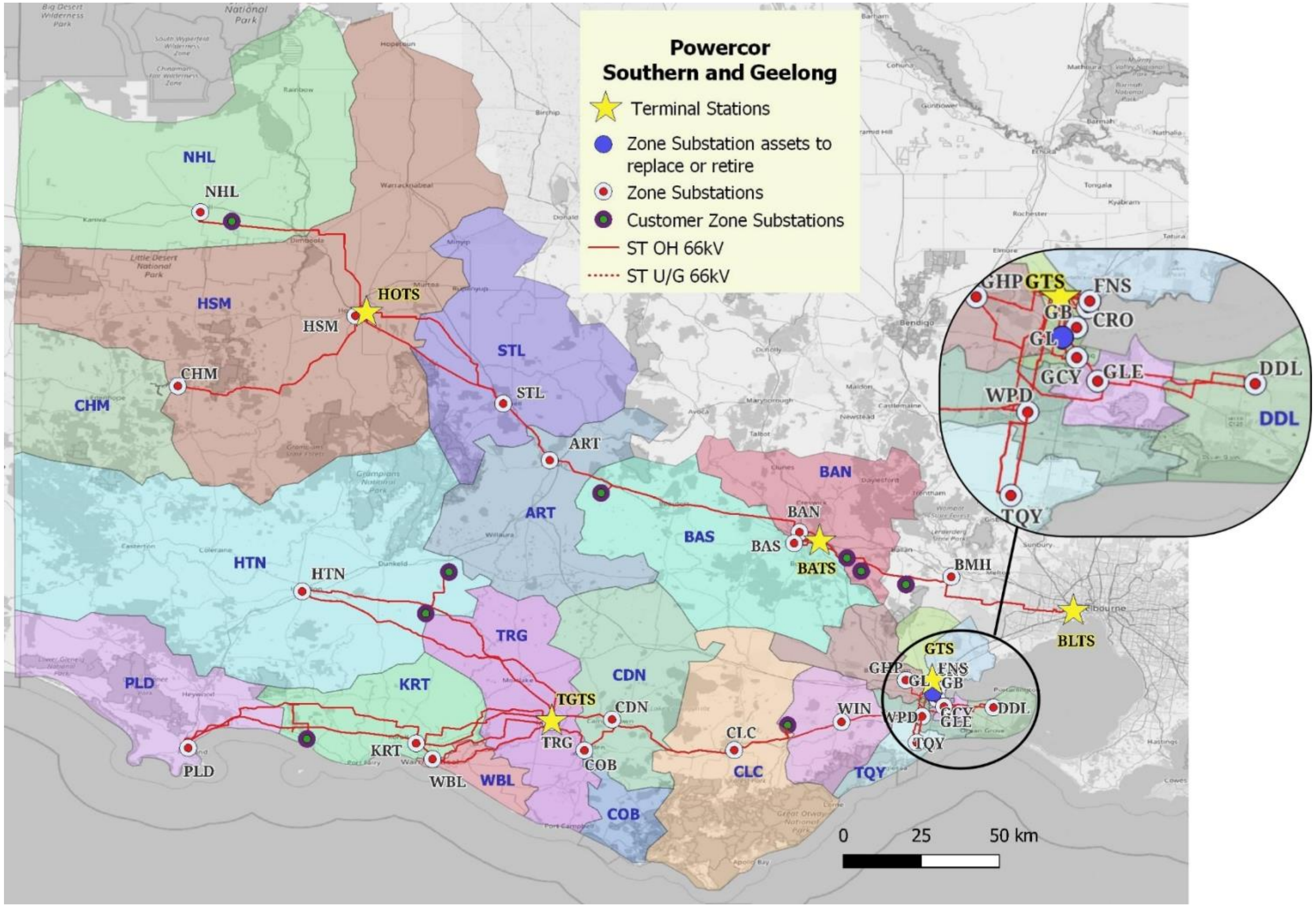
C.1. Northern area zone substations with assets to be replaced or retired



C.2. Central area zone substations with assets to be replaced or retired



C.3. Southern area zone substations with assets to be replaced or retired



Glossary and Abbreviations

C.4. Glossary

Common Term	Description
kV	kilo Volt
Amps	Ampere
MW	Mega Watt
MWh	Mega Watt hour
MVA	Mega Volt Ampere
Firm Rating	The cyclic station output capability with an outage of one transformer. Also known as the N-1 Cyclic Rating.
N Cyclic Rating	The station output capacity with all transformers in service. Cyclic ratings assume that the load follows a daily pattern and are calculated using load curves appropriate to the season. Cyclic ratings also take into consideration the thermal inertia of the plant.
N-1 Cyclic Rating	The cyclic station output capability with an outage of one transformer.
Capacity of Line (Amps)	The line current rating which takes into consideration the type of line, conductor materials, allowable insulation temperature, effect of adjacent lines, allowable temperature rise and ambient conditions. It should be noted that Powercor operates many types of underground cables in its sub-transmission system. The different types of underground cables have varying operating parameters that in turn define their ratings.
MVA above either WCR or SCR	The amount of demand forecast to exceed the Winter Cyclic Rating or the Summer Cyclic Rating.
% Above Capacity	The percentage by which the forecast maximum demand exceeds the N-1 cyclic rating.
Energy at risk	The amount of energy that would not be supplied (or the amount of generation that would need to be curtailed) if a major outage of a transformer or sub-transmission line occurs at the station or sub-transmission loop in that particular year, and no other mitigation action is taken.
Annual hours per year at risk	The number of hours in a year during which the 50th percentile demand forecast exceeds the zone substation N-1 Cyclic Rating or sub-transmission line rating.
Import rating	Import ratings define the network capability to transfer forward power flows (i.e., flows downstream towards customer loads) at that location.
Export rating	Export ratings define the network capability to transfer reverse power flows (flows from that location upstream towards the transmission point of connection).
Maximum demand	The highest amount of net electrical power imported (or forecast to be imported), from the grid to supply customers (in aggregate) for a particular season (summer and/or winter) or the year. This is also referred to as the peak load, as seen by the network.
Minimum demand	The lowest amount of net electrical power imported (or forecast to be imported), from the grid to supply customers (in aggregate) for the year. If this is not greater than zero, then it is the highest amount of net electrical power exported (or forecast to be exported), into the grid from embedded generating units (as seen by the network, in aggregate) for the year. This is also referred to as the peak supply, as seen by the network.

C.5. Zone substation abbreviations

Abbreviation	Powercor Zone Substation	Abbreviation	Powercor Zone Substation
AC	Altona Chemicals	**KRT**	Koroit
AL	Altona	**KYM**	Kyabram
ART	Ararat	**LV**	Laverton
BAN	Ballarat North	**LVN**	Laverton North
BAS	Ballarat South	**MBN**	Merbein
BBD	Boundary Bend	**MDA**	Mildura
BGO	Bendigo	**MLN**	Melton
BMH	Bacchus Marsh	**MNA**	Mooroopna
CDN	Camperdown	**MRO**	Maryborough
CHA	Cohuna	**NHL**	Nhill
CHM	Charam	**NKA**	Numurkah
CLC	Colac	**OYN**	Ouyen
CME	Cobram East	**PLD**	Portland
CMN	Castlemaine	**RVL**	Robinvale
COB	Cobden	**SA**	St Albans
CRO	Corio	**SHL**	Swan Hill
CTN	Charlton	**SHN**	Shepparton North
DDL	Drysdale	**SHP**	Stanhope
DLF	Docklands	**SSE**	Sunshine East
ECA	Echuca	**STL**	Stawell
EHK	Eaglehawk	**STN**	Shepparton
FNS	Ford North Shore	**SU**	Sunshine
GB	Geelong B	**TQY**	Torquay
GCY	Geelong City	**TRG**	Terang
GHP	Gheringhap	**WBE**	Werribee
GL	Geelong	**WBL**	Warrnambool
GLE	Geelong East	**WIN**	Winchelsea
GSB	Gisborne	**WMN**	Wemen
HSM	Horsham	**WND**	Woodend
HTN	Hamilton	**WPD**	Waurn Ponds

C.6. Terminal station abbreviations

Abbreviation	Terminal Station (AusNet Services Asset)	Abbreviation	Terminal Station (AusNet Services Asset)
ATS	Altona	**HOTS**	Horsham
BATS	Ballarat	**KGTS**	Kerang
BETS	Bendigo	**KTS**	Keilor
BLTS	Brooklyn	**RCTS**	Red Cliffs
DPTS	Deer Park (TransGrid)	**SHTS**	Shepparton
FBTS	Fishermans Bend	**TGTS**	Terang
GTS	Geelong	**WETS**	Wemen