



POWERCOR

DISTRIBUTION

ANNUAL

PLANNING

REPORT

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.

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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).

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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 2022 as well as the forward planning period of 2023 to 2027.

Powercor is a regulated Victorian electricity distribution business. It distributes electricity to more than 900,000 homes and businesses in central and western Victoria, as well as Melbourne's outer western suburbs. The network consists of 598,510 poles and over 75,526 kilometres of wires. Electricity is received via 132 sub transmission lines at 59 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 intends to hold a public forum to discuss this DAPR in early 2023. All interested stakeholders are welcome to attend, including interested parties on Powercor's demand-side engagement register, and local councils.

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

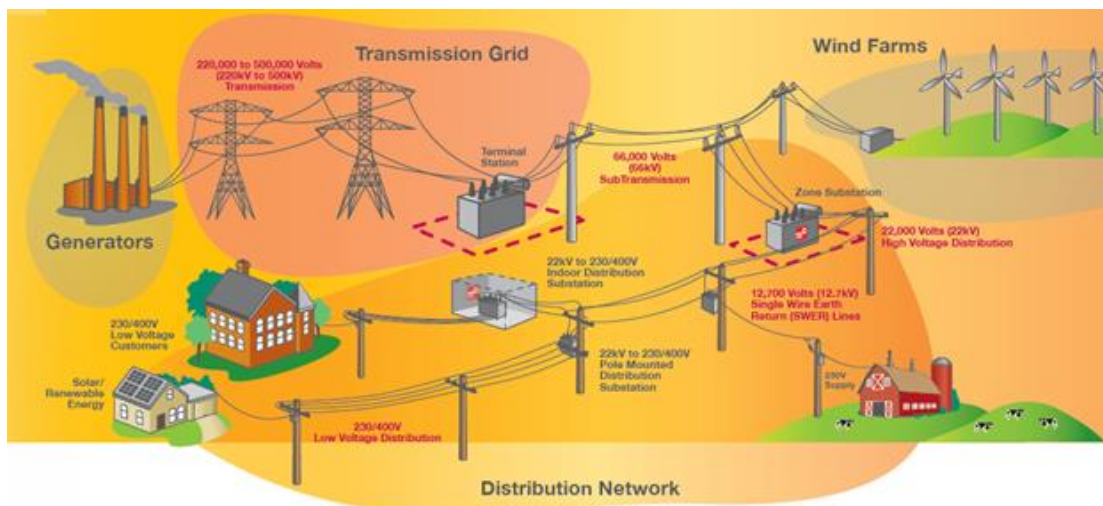
This chapter sets out background information on Powercor Australia Ltd (**Powercor**) and how it fits into the electricity supply chain.

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.

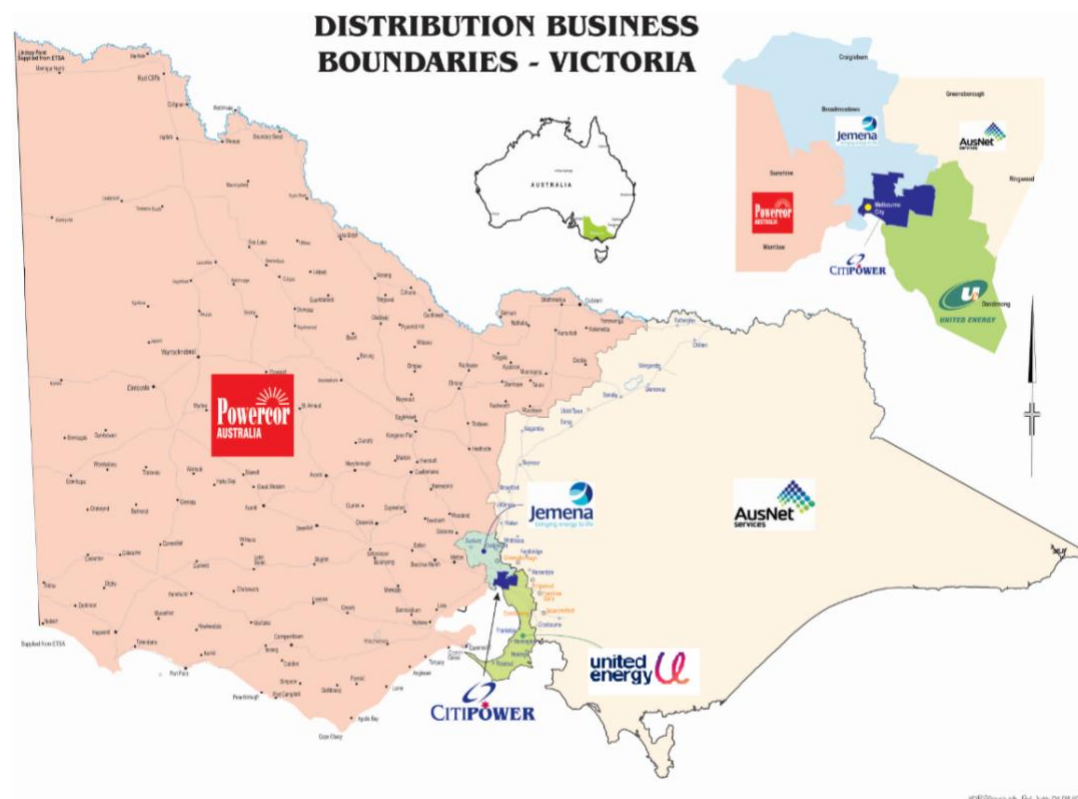
2.2 The five Victorian distributors

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

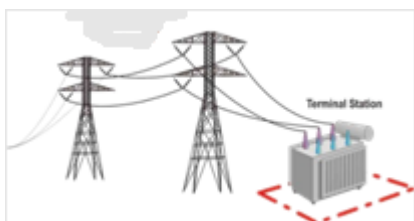


In Victoria, each DNSP has responsibility for planning the augmentation of their distribution network. In order to continue to provide efficient, secure and reliable supply to its customers, Powercor must plan augmentation and asset replacement of the network to match network

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.

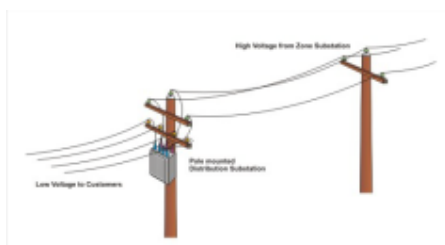


Firstly, the voltage of the electricity that is delivered to **terminal stations** is reduced by transformers. Typically in Victoria, most of the transmission lines operate at voltages of 500,000 volts (500 kilovolts or kV) or 220,000 volts (220kV). The transformer at the terminal station reduces the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



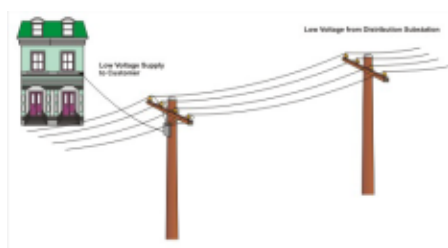
Second, Powercor distributes the electricity on the **sub-transmission system** which is made up of large concrete or wooden power poles and powerlines, or sometimes underground powerlines. The sub-transmission system transports electricity to Powercor's zone substations at 66kV.

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 900,000 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 83 per cent overhead lines and 17 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 2021-22FY, the Powercor network comprises approximately:

Table 2.1 Powercor network statistics

Item	Number / km
Poles	598,510
Overhead lines	75,526
Underground cables	15,622
Sub-transmission lines	132
Zone substation transformers	146
Distribution feeders	459
Distribution transformers	88,006

Appendix A 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

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.

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 short circuit 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 estimates the prospective fault current to ensure it is within allowable limits of the electrical equipment installed, and to select and set 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 Powercor:

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 listed above, 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 Ageing and 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 and a new Victorian Government policy subsidising solar PV for up to 650,000 households over 10 years.

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

Powercor's 'Hotspots' pilot project was fully completed in 2021 and has improved solar hosting capacity for over 150,000 of our customers. The Powercor solar network optimisation project is delivering further interventions across the remainder of the network with works continuing through 2022. When works have been completed and solar hosting capacity is improved, Powercor will advise previously constrained customers that they have the opportunity to reapply for an increased solar export capacity.

Further works involving high and low voltage interventions and system upgrade activities are planned for 2023, 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
- progressing the installation of reactive compensation devices to lower network voltages during periods of high solar penetration
- DVMS enhancements and implementing at other voltage control zones outside of Powercor zone substations

3.8 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 2013 (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 2022, Powercor commissioned REFCLs at Hamilton (HTN), Waurin Ponds (WPD), and Torquay (TQY).

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	2023	Planned for 2023
Eaglehawk (EHK)	New transformer and additional REFCL	2025	In plan
Gisborne (GSB)	Additional REFCL	2026	In plan
Ararat (ART)	Feeder rearrangement	2026	In plan

Zone substation	Project description	Year	Status
Bendigo (BGO)	Feeder rearrangement	2027	In plan
Winchelsea (WIN)	New transformer and additional REFCL	2027	In plan
Ballarat East (BAE) / Ballarat West (BAW)	New zone substation with transformers and additional REFCL	2025	Initial intervention works planned for 2022 and 2023. Options analysis in progress. Ballarat East is an additional option for the Ballarat West new zone substation described in the 2021 DAPR.

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
Hamilton (HTN)	2022
Waurm Ponds (WPD)	2022
Torquay (TQY)	2022
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 will be constructed at Gheringhap (GHP). Torquay (TQY) will be commissioned in conjunction with Waurm Ponds (WPD) as the capacitance of the network has grown considerably since the REFCL legislation was introduced beyond the rating of the REFCL's proposed for Waurm 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 Powercor's 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	2022	2023
Feeders	• DDL023, GCY014, GL021, GLE012, GLE013 (from WPD) • TQY011, TQY012, TQY021, TQY022, (from WPD)	• 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.

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.²

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 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). For summer, it relates to a maximum average temperature that will be exceeded, on average, once every two years. By definition therefore, actual demand in any given year has a 50 per cent probability of being

² <https://www.powercor.com.au/what-we-do/the-network/network-planning/>

higher than the 50th percentile demand forecast.³ The 50th percentile forecast can therefore be considered to be a forecast of the “most-likely” level of demand, bearing in mind that actual demand will vary depending on temperature and other factors. It is often referred to as 50 per cent probability of exceedance (**PoE**).

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 (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 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

³ Consequently there is also a 50% probability that demand will not reach forecast.

- **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 $\geq$ 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 zone substation 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 outage⁴ 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.

⁴ 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.

Estimates of energy at risk are based on the 50th percentile demand forecasts, which were discussed in sections 5.2 and 5.3.

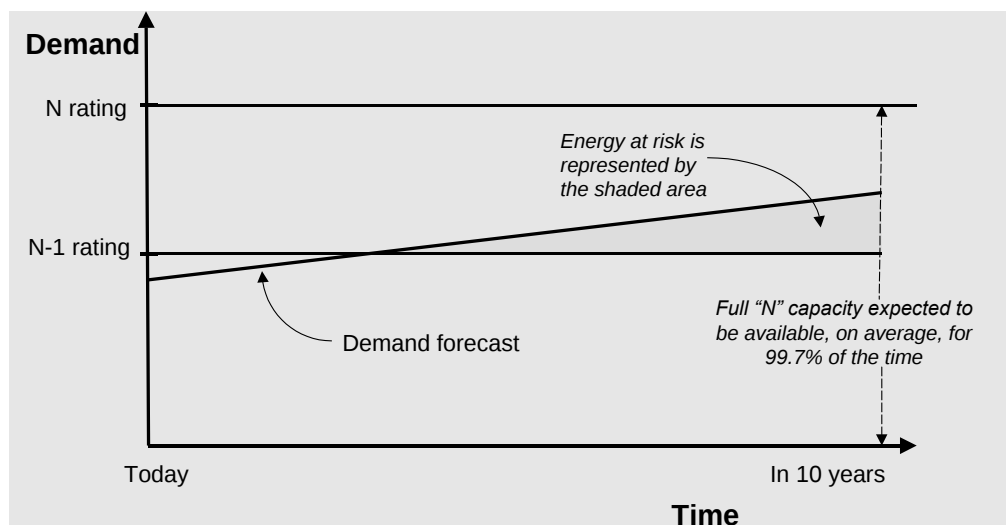
6.2 Interpreting “energy at risk”

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 2019. The applicable Powercor VCR values from this publication are as per Table 6.1 below:

Table 6.3 Values of customer reliability

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 study⁵
- Oakley Greenwood's 2012 estimate of the New South Wales VCR⁶, of \$95 per kWh
- AER's latest Victorian VCR⁷ 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 Valuing generation curtailment

In order to determine the economically optimal level and configuration of distribution capacity that would be provided to embedded generators for the export of power into the network, it is necessary to place a value on energy curtailed from embedded generators at times when the export capacity is breached.

On 12 August 2021, the AEMC made a final determination on its "Access, pricing and incentive arrangements for distributed energy resources" Rule change⁸. 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 Note⁹, 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.

⁵ See section 2.4 of the 2013 Transmission Connection Planning Report.

⁶ AEMO, Value of Customer Reliability Review Appendices, November 2014.

⁷ AER, Values of Customer Reliability, Final Report on VCR Values, December 2019.

⁸ AEMC, Rule Determination, National Electricity Amendment (Access, Pricing and Incentive Arrangements for Distributed Energy Resources) Rule 2021, 12 August 2021.

⁹ <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure-guidance-note/final-decision>

Powercor has not published values for generation curtailment in this DAPR as the method and value for determining generation curtailment is still being assessed. It is intended to publish these values in next year's DAPR.

7 Zone Substations Review

This chapter reviews the zone substations 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 maximum demand to 2027
 - summer and winter cyclic N-1 import ratings for each zone substation
- Export limitations:
 - forecasts for minimum demand to 2027
 - cyclic N-1 export ratings for each zone substation

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 2023 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.

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 7.1 Proposed import-limited zone substation augmentations

Zone substation	Description	Direct cost estimate (\$ millions)				
		2023	2024	2025	2026	2027
BAE / BAW	New REFCL Zone Substation subtransmission lines and HV feeders	2.7	14.0	18.0	0.3	
BMH	BMH ZSS new transformer, circuit breakers, 66kV/22kV works and control room	0.15	0.33	2.5	3.5	0.7
EHK	New transformer and REFCL		3.9	3.9		
GSB	New REFCL			0.4	3.8	
TRT	New zone substation subtransmission lines and HV feeders			30		
WIN	New transformer and REFCL				0.8	7.4

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)				
		2023	2024	2025	2026	2027
Nil	-	=	=	=	=	=

Whilst 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.

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/UaPnYl6yeV>

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 constraint 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 with two REFCLs for an estimated cost of \$35.0 million
- install isolating substations with REFCLs on BAN/BAS 22kV feeders for an estimated cost of \$30.7 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 \$41.1 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 constraint 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 with two REFCLs for an estimated cost of \$35.0 million
- install isolating substations with REFCLs on BAN/BAS 22kV feeders for an estimated cost of \$30.7 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 \$41.1 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 Bendigo (BGO) zone substation REFCL

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 2027 there will be 6.1 MVA of load at risk and for 16 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 13.1MVA
- install a new 25/33MVA third transformer at BGO zone substation for an estimated cost of \$5.9 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.

Powercor estimates that a REFCL constraint is forecast at BGO by 2028 due to increasing charging current and network damping from future customer developments. To address the anticipated system constraint at BGO zone substation, Powercor considers that the following network solutions could be implemented to manage REFCL compliance risk:

- 22kV feeder rearrangement between BGO/BETS for an estimated cost of \$1.2 million
- installing a new 25/33MVA third transformer and REFCL, and complete associated station work at BGO for an estimated cost of \$8.3 million.

Powercor's preferred option is to rearrange the 22kV feeders between BGO and BETS in 2027 to maintain Powercor's REFCL compliance requirements.

7.2.5 Bacchus (BMH) Marsh 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 14.1 MVA of load at risk and for 653 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 5.3MVA
- 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 14.1 MW at this zone substation would defer the need for this capital investment by one year to 2028.

7.2.6 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 2023 there will be 19.6 MVA of load at risk for 159 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 Waurin Ponds (**WPD**) up to a maximum transfer capacity of 10.6 MVA
- permanently transfer load away from DDL to GLE by constructing a new feeder at GLE for an estimated cost of \$2.4 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 2023. Therefore a demand side initiative to reduce the forecast maximum demand load by 19.6MVA at this zone substation would defer the need for this capital investment by one year to 2024.

7.2.7 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 2026 there will be 22.7 MVA of load at risk and for 327 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 17.6 MVA
- install a new 25/33MVA third transformer at EHK zone substation for an estimated cost of \$5.5 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 \$7.8 million.

Powercor's preferred option is to install a new transformer and REFCL at EHK by 2026. 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.

7.2.8 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 2027 there will be 12.1 MVA of load at risk for 429 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 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 (**GL**), Geelong East (**GLE**) and Waurin Ponds (**WPD**) up to a maximum transfer capacity of 16.4 MVA
- augment capacity by installing an additional 66/22kV transformer at GCY (and complete other associated station works) for an estimated cost of \$6.0 million.

Powercor's preferred option is to install an additional 25/33MVA transformer and complete other station upgrade works at GCY, however given that the forecast annual hours at risk is low, this project is not expected to be required until the summer of 2026/27. Consequently, Powercor is expecting to commence scoping a project to address this constraint in 2025. 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.

7.2.9 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 27.4 MVA of load at risk and for 85 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 9.8 MVA in 2022/2023.
- build a new zone substation at Tarneit (**TRT**) for a cost of \$30m in 2025 and transfer load away from LV.

Powercor's preferred option is to build Tarneit (**TRT**) 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 27.4 MVA across these zone substations would defer the need for this capital investment by one year to 2026.

7.2.10 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 2027 there will be 14.3 MVA of load at risk and for 186 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 installing a third 25/33MVA transformer at nearby Mildura Zone substation (**MDA**) for an estimated cost of \$5.6 million and permanently transfer load to MDA.

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.

7.2.11 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 2027 there will be 9.4 MVA of load at risk and for 63 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 15.2 MVA
- augment capacity by installing a third 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.

7.2.12 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 2027 there will be 4.9 MVA of load at risk and for 18 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 8.5 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.

7.2.13 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 2027 there will be 6.0 MVA of load at risk and for 71 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 4.0MVA
- 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.

7.2.14 Robinvale (RVL) zone substation

The zone substation in Robinvale (RVL) is served by sub-transmission lines Bannerton Solar Park (BSP) and Wemen Terminal to Wemen Solar Farm (WETS-WMN). It supplies the area of Robinvale extending into surrounding areas.

Currently, the RVL zone substation is comprised of two 5/6.5MVA transformers and one new 25/33MVA transformer operating at 66/22kV. The operation arrangement is that new 25/33MVA transformer supplying the load and two other transformers connected as hot stand by. 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 4.5 MVA of load at risk (in case of loss of 25/33MVA transformer) and for 33.5 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 RVL. 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 RVL 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 Boundary Bend zone substation (**BBD**) and Wemen zone substation (**WMN**) up to a maximum transfer capacity of 4.3 MVA.
- replace second transformer at RVL zone substation.

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 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.

7.2.16 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 2027 there will be 1.8 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.

7.2.17 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 40.4 MVA of load at risk and for 159 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 Tarneit (**TRT**) for a cost of \$30m in 2025 and transfer load away from WBE.

Powercor's preferred option is to build Tarneit (**TRT**) 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 40.4 MVA in 2025 across these zone substations would defer the need for this capital investment by one year.

7.2.18 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 2027 there will be 6.2 MVA of load at risk and for 95 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.

7.2.19 Winchelsea (WIN) zone substation REFCL

The zone substation in Winchelsea (**WIN**) is served by two sub-transmission lines from Geelong terminal station (GTS) and Terang terminal station (TGTS). It supplies the Winchelsea area.

Currently, the WIN zone substation is comprised of one 5MVA transformer and one 10MVA transformer operating at 66/22kV, and has two REFCLs.

Powercor estimates that a REFCL constraint is forecast at WIN by 2028 due to increasing charging current and network damping from future customer developments. To address the anticipated system constraint at WIN zone substation, Powercor considers that the following network solutions could be implemented to manage REFCL compliance risk:

Installing a new 10MVA third transformer and REFCL, and complete associated station work at WIN for an estimated cost of \$41.1 million.

- installing a new 10MVA third transformer and REFCL, and complete associated station work at WIN for an estimated cost of \$8.3 million.
- install a new zone substation in the Winchelsea area for an estimated cost of \$35.0 million.

Powercor's preferred option is to install a new 10MVA third transformer and REFCL, and complete associated station work at WIN in 2027 to maintain Powercor's REFCL compliance requirements.

7.2.20 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 constraint 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 at GSB, and transfer sections of WND via 22kV links for an estimated cost of \$4.2 million.
- installing a new 25/33MVA third transformer and REFCL, and complete associated station work at WND for an estimated cost of \$8.3 million.

Powercor's preferred option is to install a new REFCL 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

7.3.1 Tarneit zone substation (TRT)

The new Tarneit zone substation (**TRT**) is proposed to commence option analysis, scope concept and design in 2022 and 2023. TRT is to be commissioned to support the growth in the western suburbs of Melbourne as the continued urban residential development (URD) is growing beyond the capacity of the existing electrical network infrastructure.

7.3.2 Ballarat East/West zone substation (BAE/BAW)

A new zone substation in the Ballarat area is proposed to commence option analysis, scope concept and design in 2022 and 2023. The new zone substation is to be commissioned 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 2027
 - line import ratings for each subtransmission line
- Export limitations:
 - forecasts for N-1 minimum demand to 2027
 - 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)				
		2023	2024	2025	2026	2027
ATS-WBE-HCP	Load at risk is forecasted for these sub-transmission lines but will be managed without proposing sub-transmission line augmentation	-	-	-	-	-
BETS-BGO-EHK		-	-	-	-	-
GTS-GB-GL-GCY		-	-	-	-	-
GTS-GLE-DDL		-	-	-	-	-
KGTS-GSF-SHL		-	-	-	-	-
RCTS-MDA-MBN		-	-	-	-	-

Powercor proposes to augment sub-transmission 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		-	-	-	-	-
KRT-PLD2/YWF		-	-	-	-	-
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 subtransmission lines with forecast limitations can be found at the link below by searching for sub-transmission system limitation report:

<https://spaces.hightail.com/space/UaPnYl6yeV>

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 2027 for the lines within this loop there will be:

- 37.8 MVA of load at risk and for 30 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
- 37.9 MVA of load at risk and for 30 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 8.7 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 3.4 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 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 2027 for the lines within this loop there will be 13.1 MVA of load at risk, and for 34 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 10.2 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.

8.2.3 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 2027 for the lines within this loop there will be:

- 34.1 MVA of load at risk and for 21 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
- 1.1 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 16.6 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.

8.2.4 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 2026 for the lines within this loop there will be:

- 39.2 MVA of load at risk and for 10 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
- 28.5 MVA of load at risk and for 6 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.

8.2.5 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 2027 for the lines within this loop there will be 19.91 MVA of load at risk and for 3826 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) and Ouyen (OYN) zone substations up to a maximum transfer capacity of 1.5 MVA
- contingency plan to transfer load away via 22kV links to the Kerang terminal station (KGTS 22kV) up to a maximum transfer capacity of 1.0 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.

8.2.6 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 2027 for the lines within this loop there will be 30.0 MVA of load at risk, and for 92 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 8.6 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.

8.2.7 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 2027, 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.

8.2.8 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 2027, there will be:

- for limitations on GTS-WIN, 61.9 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, 26.0 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.

8.2.9 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 2027, for limitations on KGTS-GSF there will be:

- 14.8 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.

8.2.10 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 2027, there will be:

- for limitations on RCTS-KSF, 12.7 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, 9.4 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.

8.2.11 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 2027, for limitations on SHTS-NSF there will be:

- 31.3 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.

8.2.12 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 2027, there will be:

- for limitations on TGTS-HTN, 34.7 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, 29.3 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.

8.2.13 KRT-PLD2/YWF 66 kV sub-transmission line export limitation

The KRT-PLD2/YWF 66kV sub-transmission line forms part of the KRT-CWF/PLD/YWF-KRT sub-transmission loop ex the TGTS-KRT-WBL-TGTS 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 2027, for limitations on KRT-PLD2/YWF there will be:

- 7.4 MVA of generation at risk of curtailment if there is an outage of the KRT-PLD1/CWF 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 YWF (and potentially other sites) to manage the line loading under contingency conditions.
- Upgrade the KRT to PLD2/YWF-tee section of this sub-transmission line.

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
Waurm Ponds (WPD) to Torquay (TQY) second 66kV line	To supply the new TQY zone substation	2023
Tarneit (TRT) two new 66kV lines	To supply the new TRT zone substation	2025
Gheringhap (GHP) two new 66kV lines	To supply the new GHP zone substation	2023

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 2027
 - cyclic 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 2023, 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.

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.

Whilst 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 2024
 - summer and winter cyclic import ratings for each feeder
- Export limitations:
 - forecasts for minimum demand to 2024
 - 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
BMH004	Augment feeder backbone	0.96	

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>

10.1.1 BMH004 (augment)

The Bacchus Marsh (BMH) zone substation supplies the domestic, commercial, industrial and farming areas of Bacchus Marsh, Balliang and surrounding areas along the Western Freeway. It comprises two 10/13.5MVA transformers operating at 66/22kV.

BMH004 feeder is one of four 22kV feeders supplying the area surrounding BMH zone substation. The load along this feeder is forecast to exceed its thermal limitation due to continued residential and commercial development.

Powercor estimates that on BMH004 feeder, in summer 2023, there will be 1.7 MVA of unserved load above the thermal rating for 12 hours during system normal conditions. In subsequent summers, load along this feeder will be above thermal rating during system normal conditions. That is, it would not be able to supply all customers along this feeder during high load periods.

This feeder has limited ties, hence there is no opportunity to transfer loads to adjacent feeders.

Given the load forecast, we will not be able to supply all customers during high load periods. To address the anticipated system constraint, we considered the following network solutions:

- construct a new BMH 22kV feeder at an estimated cost exceeding \$1.5 million
- augment BMH004 feeder backbone at an estimated cost of \$961k.

The lowest cost option is to augment BMH004 feeder in 2023. This will eliminate the forecast overload and allow for further load growth. A demand side initiative to reduce the forecast maximum demand load by 1.7 MW on BMH004 feeder would defer the need for this capital investment by one year to 2024.

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)	
		2023	2024
GHP011, GHP012, GHP021, GHP022	Redirect existing 22kV feeders to new REFCL ZSS (Costs included within table 7.1 costs)	2.2	
BAS013	Construction of new BAS013 feeder		1.1
BAS031	Construction of new BAS031 feeder	1.3	
GLE022	Construction of new GLE022 feeder	2.2	
WMN014	Construction of new WMN014 feeder		0.4

10.2.1 BAS013 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 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 BAS013 feeder to Alfredton will offload BAS011 and BAS024 feeders.

Load on BAS011 feeder has already exceeded feeder winter N rating in previous winters. There is significant ongoing residential development at Lucas and Delacombe, being supplied from BAS011 feeder and also BAS024 feeder.

Powercor estimates that in winter 2024, there will be 2.2MVA of unserved load above the thermal rating for 291 hours during system normal conditions.

Based on load forecasts and to address constraints the following network solutions have been considered.

- construct a new BAS013 feeder to Alfredton at an estimated cost of \$1.1 million by 2024.
- augment feeder exits and backbones on BAS011 & BAS024 feeders at an estimated cost of \$1.5 million

The construction of new BAS013 feeder is the preferred option as it is the least cost option that removes forecast demand load by 2.2MVA on BAS011 feeder and also reduces load on BAS024 feeder. A demand side initiative to reduce the forecast maximum demand by 2.2MVA on BAS011 feeder would defer the need for this capital investment by one year in 2024.

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 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 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.

10.2.3 GLE022 feeder

The Drysdale (DDL) zone substation supplies domestic, commercial and industrial areas of Drysdale, Clifton Springs, Curlewis, Leopold, Wallington, Ocean Grove, Barwon Heads, Point Lonsdale, Queenscliff, Portarlington, Indented Head, Portarlington & St Leonards on the Bellarine Peninsula. It comprises two 20/27/33MVA transformers and eight 22kV feeders.

Over the summer holiday period during December and January each year there is a substantial influx of holiday makers on the Bellarine Peninsula and hence a substantial increase in load at DDL zone substation. There are minimal transfers away from DDL zone substation, presently available transfers away from DDL zone substation are only to GLE024 and GLE031 feeders. Both GLE024 and GLE031 feeders have substantial load over the summer period and hence minimal spare capacity for transfers from DDL zone substation.

The Geelong East (GLE) zone substation supplies domestic, commercial and industrial areas in the Geelong suburbs of East Geelong, Armstrong Creek, Grovedale, Belmont, Breakwater, Newcomb and Leopold. It comprises two 25/33MVA transformers and one 10/13.5MVA and nine 22kV feeders.

A new GLE022 feeder to Leopold will offload GLE013, GLE024 and GLE031 feeders and provide greater transfers away from DDL zone substation. GLE024 and GLE031 feeders supply Leopold which also has ongoing significant ongoing residential development. Load on GLE013 feeder has already exceeded feeder summer N rating in previous summers. There is significant ongoing residential development at Armstrong Creek being supplied from GLE013 feeder.

Powercor estimates that on GLE013 feeder, in Summer 2024, there will be 3.4 MVA of unserved load above the thermal rating for 11 hour during system normal conditions. Based on load forecasts and to address constraints the following network solutions have been considered:

- construct a new GLE022 feeder to Leopold at an estimated cost of \$2.2 million
- augment feeder exits and backbones on GLE013, GLE024 & GLE031 feeders at an estimated cost of \$2.4 million.

The construction of new GLE022 feeder is the least cost option that removes forecast overload on GLE013 feeder, reduces load on GLE024 & GLE031 feeders and enhances transfers away from DDL zone substation. This network investment has been approved for commencement in 2023. Please refer to the System Limitations Template for further information regarding the network investment after the project has been completed.

A demand side initiative to reduce the forecast maximum demand load by 3.4 MW at DDL zone substation would defer the need for this capital investment by one year to 2024.

10.2.4 WMN014 feeder

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 2026 there will be 7.7 MVA of load at risk and for 115 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 \$3 million.
- further enhance the load transfer capability from WMN to RVL by building a new feeder using redundant 66kV line between RVL and WMN and also increasing new load connection capacity at an estimated cost of \$0.4 million.

The construction of new WMN014 feeder is the preferred option as it is the least cost option that enhances transfers away from WMN. A demand side initiative to reduce the forecast maximum demand by 7.7 MVA on WMN would defer the need for this capital investment by one year in 2024.

The following primary distribution feeder projects are proposed to commence scope investigation and option analysis in 2023-24.

Table 10.4 Future primary distribution feeder projects

BAN002 feeder exit augmentation	LV004 feeder exit augmentation
MLN new feeder	WMN feeder augmentation

11 Joint Planning

Powercor has not identified any new projects from our joint planning activities with other DNSPs in 2022. 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 2021

The following information details load forecasts and project timing changes that have occurred since the publication of the 2021 DAPR.

12.1 Constraints addressed or reduced due to projects completed

Powercor has undertaken the following projects in 2022 to address constraints identified in the 2021 DAPR:

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

12.2 New constraints identified

Changes in load forecasts or other factors during 2022 have resulted in Powercor undertaking risk assessments for the following zone substations or sub-transmission lines, which were not included in the 2021 DAPR:

- Robinvale (**RVL**) zone substation load forecasts have increased, resulting in load and hours at risk above threshold limits
- Minimum demand forecasts produced during 2022 have identified the following sub-transmission lines with generation at risk of curtailment:
 - BAN-BGR
 - GTS-WIN
 - WIN-MGW
 - KGTS-GSF
 - RCTS-KSF
 - SHTS-NSF
 - TGTS-HTN
 - NRB-HTN
 - TGTS-NRB

-
- KRT-PLD2/YWF
 - WETS-WSF
 - WETS-BSP

12.3 Other material changes

In addition to the matters identified above, material changes compared to the 2021 DAPR include:

- Horsham (**HSM**) load forecasts have decreased, resulting in load and hours at risk below threshold limits
- Stawell (**STL**) load forecasts have decreased, resulting in load and hours at risk below threshold limits
- Sunshine (**SU**) load forecasts have decreased, resulting in load and hours at risk below threshold limits

13 Asset Management

This chapter provides information on the Powercor asset management approach including the strategy employed, impacts on system limitations and where further details can be obtained.

13.1 Asset Management System Framework

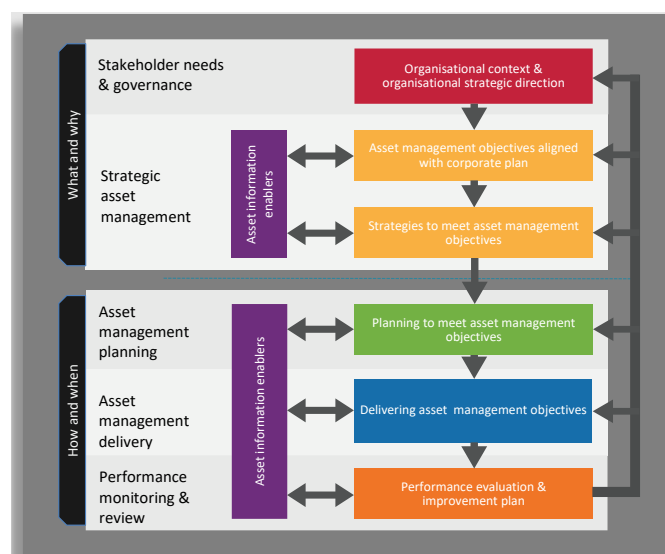
Powercor is committed to the application of best practice asset management strategies to ensure the safe and reliable operation of our electrical network. Powercor is continuing to develop and implement an asset management system that is aligned with the requirements of ISO 55001:2014, the international standard in asset management.

The Asset Management System (**AMS**) Framework is a high-level document that describes the asset management system that Powercor applies to its network assets. The AMS Framework identifies Powercor's asset management roles, accountabilities and all significant steps and processes involved in the asset life cycle, from the identification of need to creation, operation, maintenance and eventual disposal. Our AMS consists of five key levels:

- Level 1: Stakeholder needs and governance
- Level 2: Strategic asset management
- Level 3: Asset management planning
- Level 4: Asset management delivery
- Level 5: Performance monitoring and review

The structure and hierarchy of the AMS Framework is illustrated in Figure 12.1.

Figure 13.1 Asset Management Framework



- Levels 1 and 2 describe 'What' asset management strategies and objectives are to be targeted and provide details regarding 'Why' these are required. Level 3 describes the approach taken to plan and budget for the delivery of the asset management activities, while level 4 describes 'How' and 'When' these activities are delivered to meet the strategies and objectives. Level 5 describes Powercor's approach to performance monitoring and review of the asset management system.
- The relationships between Powercor's strategic asset management documentation are shown in figure 12.2. These strategic documents describe what asset management strategies and objectives are to be targeted and provide details regarding why these are required.

Figure 13.2 Strategy and planning document hierarchy



- An overview of these documents is provided in the following sections.

13.1.1 Strategic Asset Management

Powercor's asset management strategies and objectives are aligned to the asset management policy and to the needs of our stakeholders, including the direction articulated in our organisational strategic pillars and the asset management-related commitments made in our approved regulatory submission.

The strategic asset management level of Powercor's AMS framework comprises the following key components:

- Asset management objectives
- Asset management policy
- Strategic Asset Management Plan (**SAMP**)
- Asset management strategies
- Asset class strategies

13.1.1.1. Asset Management Objectives

Powercor's asset management objectives form the basis for evaluating the success of the asset management system in delivering against the organisational strategic pillars.

The asset management objectives for Powercor are:

- 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.

The AMS Framework maps the asset management policy principles and asset management objectives to demonstrate the alignment to the organisational strategic pillars.

13.1.1.2. Asset Management Policy

Powercor's Asset Management (**AM**) Policy drives all asset management activities in our organisation. The AM Policy is a high-level statement providing:

- our overall approach to asset management
- the principles to be followed, and direction for establishing asset management strategies and objectives
- management expectations regarding asset management outcomes.

The AM Policy requires asset management activities to meet business objectives and benefit the current and future needs of all customers, stakeholders and employees.

13.1.1.3. Strategic Asset Management Plan

- Powercor's strategic asset management plan (**SAMP**) identifies our high-level strategies and objectives for asset management, and links these to the 'five strategic pillars', providing line of sight to the organisational strategy. The SAMP takes full account of our approaches to network risk and asset investment decision making, and provides long-term guidance for the development of the asset management strategies and class strategies.

13.1.1.4. Asset Management Strategies

Asset management strategies have been developed for eight subject areas to deliver Powercor's SAMP objectives. The Asset Management Strategy subjects are not asset specific and apply across all asset classes. Individual subject strategies are developed by considering:

- Powercor's organisational context and key asset management issues of a range of internal stakeholders
- The asset management requirements of a range of external stakeholders, including the AER, AEMO and CFA.

The asset management strategies provide guidance for development of asset operational plans and asset management plans, to prioritise and deliver the asset management

objectives and strategies. Refer to appendix D for a detailed list of the asset management strategy subjects and purpose of each strategy.

13.1.1.5. Asset Class Strategies

Powercor has identified sixteen asset class strategies (ACS) for which specific strategies and objectives have been developed, all of which are aligned to the SAMP. Each ACS is formed from analysis of the required performance in terms of reliability and quality of supply, risk profile, functionality, availability and safety. The ACSs provide guidance for development of asset operational plans and asset management plans, which drive inspection, maintenance, condition monitoring, maintenance policies and work instructions. Refer appendix D for a detailed list of ACS documents and corresponding asset coverage.

13.1.2 Asset Management Planning

Powercor plans its asset management activities to maximise the value realised over the life of its assets. The asset management planning stream of Powercor's AM Framework is undergoing further development, with key focusses on asset investment planning, asset maintenance requirements and optimising the asset lifecycle.

Powercor has implemented a new value framework that will form the basis for quantitatively prioritising investments. The value framework is used to configure the Copperleaf C55 asset planning and investment tool to facilitate the quantitative prioritisation of investments going forward.

13.1.3 Asset management delivery

Powercor's asset management delivery and governance is facilitated via existing standards, policy, procedures and processes that stipulate the requirements for our asset management delivery. Monitoring of compliance is achieved via regular internal audit processes and reporting. Powercor's asset management committee provides specific oversight and governance to the Asset Management System.

13.1.4 Performance monitoring and review

Powercor monitors the performance of both network assets and the asset management system as a whole. The components of Powercor's performance monitoring and review level of the AM framework are outlined below:

- risk assessment and management
- business continuity planning
- change management
- asset performance and health monitoring
- asset management monitoring and continual improvement
- audit and assurance
- stakeholder engagement.

Considerable capital investment has been made to configure the network to provide real-time asset performance data that is used to develop a range of higher and lower level

performance indicators, including those that are required to be reported under the terms of our distribution licence. Additionally, Powercor conducts a range of internal and external reviews of the network and asset management system performance through internal audits, external audits and via regular management reviews. Where improvements to the AMS are required, these are consolidated into an AMS improvement plan.

13.1.5 Impact of Asset Management on System Limitations

Electrical plant and conductor ratings may be affected by asset management activities in that a condition assessment could result in a higher or lower operating temperature. This could improve ratings to defer augmentation costs or lower ratings which will tend to bring forward expenditure whilst maximising system reliability, safety and security of supply. In addition, chapters 3 and 14 of this DAPR cover the effect on the system of ageing and potentially unreliable assets.

13.1.6 Distribution Losses

Distribution losses refer to the energy used in transporting it across distribution networks. In 2017/18, 5.73 per cent of the total energy into the Powercor network was made up of losses. This is essentially calculated as the difference between the energy that Powercor procures and that which it supplies. These losses represent 90.4 per cent of Powercor's total greenhouse gas emissions, as defined under the *National Greenhouse and Energy Report Act*.

Powercor has a process to identify, justify and implement augmentation plans to address network constraints. Whilst loss reduction alone is not the main contributing factor in the decision of the preferred option, it is seen as the deciding factor if all other factors are equal. Powercor, as part of its plant selection process takes into account the cost of losses in its evaluation for transformer purchases.

13.1.7 Contact for further information

Further information on Powercor's asset management strategy and methodology can be obtained from contacting Powercor Customer Service:

- General Enquiries 13 22 06
- Website www.powercor.com.au

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

14 Asset Management Methodologies

The Asset Management Framework (AMF) describes the Asset Management System (AMS) that is applied to Powercor's network assets, and requires the AMS to:

- support the asset life cycle
- recognise the value of assets in decision-making at each stage of the life cycle
- enable asset management decisions to be optimised based on quantified risk, asset performance and life cycle cost.¹⁰
- Powercor's assets are subject to relevant condition assessment methods through planned inspection and maintenance programs. These programs have been developed taking into account regulatory obligations, industry knowledge as well as proven and established asset management methodologies.

Powercor's preferred asset management methodologies¹¹ applied to its network assets is as follows:

- Reliability-Centred Maintenance (RCM) – Powercor applies a reliability and safety based regime which is based on the principles of RCM methodology together with regulatory obligations and risk assessment that are built into the asset management procedures. It is applied to routine replacement expenditure for high- volume assets such as poles, pole top-equipment, cross-arms, insulators, etc. The approach has regard for the asset age, condition and operating environment; and
- Condition Based Risk Management (CBRM) — this methodology is applied to determine the condition of assets from routine inspection and maintenance, including the risk of the deterioration, of major items of plant, and critical high volume asset replacements which involve significant expenditure.
- This includes assets such as zone substation transformers and switchgear.

These are discussed in more detail in the sections below.

¹⁰ Powercor and Powercor Australia Asset Management System Framework (March 2019) page 7

¹¹ Where the application of RCM or CBRM methodologies are not practical, alternative asset management methodologies are applied e.g high volume or low criticality asset classes

14.1 Reliability Centred Maintenance (RCM)

Powercor applies a reliability and safety based regime, based on RCM principles, regulatory obligations and risk assessments, it is applied to high-volume assets such as poles, cross-arms, conductors etc.

The RCM process is used to determine what must be done to ensure that our physical network assets continue to operate at their intended performance levels at the most efficient cost. It is an internationally recognised and widely used methodology used to determine the most appropriate maintenance strategy for a particular class of asset at efficient cost.

For each asset type, the RCM process identifies possible ways in which a defect may occur in an asset, and the root cause of that defect. For each different type of defect, the possible impact on the safety, operations and other equipment in the network is assessed and a maintenance strategy is determined.

When implementing the RCM methodology for the inspection of assets, the risks associated with asset failures have been considered together with the inspection and repair costs to determine the most efficient inspection frequency and timeframe for repair of identified defects. Where a defect is identified, the maintenance strategy to address that defect is implemented. This may involve either asset replacement or maintenance measures to prolong the asset's life, such as pole staking. Asset replacements for Poles assets are not determined by RCM alone, the RCM is an input into the CBRM model which provides a more granular quantification of risk and appropriate interventions.

The RCM process can be summarised by a series of steps, as follows.

Figure 14.1 Steps in the RCM process to develop a maintenance strategy

1. Select functions and performance standard of asset	• ensure the asset continues to do what its users want it to do • consider primary functions and secondary functions of asset
2. Identify function failures	• identify the ways in which the asset may fail to fulfil its functions
3. What causes each functional failure	• identify all of the events which are reasonably likely to cause each failed state • includes failures which have occurred on the same or similar equipment; are prevented by existing maintenance procedures; and those which possibly may occur
4. What happens when failure occurs	• list all failure effects that describe what happens when a failure mode occurs, including supporting evidence • e.g. what is the evidence that a failure has occurred, how does it pose a threat to safety or the environment
5. How does the failure matter	• consequences of failure of a hidden function, where failure will not become evident to operators under normal circumstances • consequence of failure of an evident function in terms of the impact on safety, environment, operational and non-operational matters
6. How to prevent or predict each failure	• identify the most appropriate maintenance strategy for each failure mode, which is also technically and economically feasible • where it is not possible to identify a pro-active task, select default actions such as proof testing, re-design or run to failure
7. Regularly review process	• once maintenance recommendations are put into practice, these are routinely reviewed and renewed as additional information is found

RCM analysis is undertaken by taking into account the equipment manufacturer's recommendations, the physical and electrical environment in which the asset is installed, fault and performance data, test data, condition data, duty cycles as well as many years of field-based experience.

The combination of general maintenance requirements and the specific requirements based on the environments in which the assets operate, may result in varying maintenance and condition monitoring regimes for the same type of asset. Tests and inspections are undertaken using tools such as thermal imagery, visual inspections, and invasive pole testing to assess asset condition.

The following example demonstrates how we apply RCM methodology in the case of wood poles, in practice:

1. Data collection — population demographics are determined so that the volume, age, strength, location and timber species is known. Each of these parameters are analysed to determine how they impact on the performance of poles and may require differing maintenance strategies. Performance data is gathered to determine defect rates, population condition, failure rates and root causes of failures.

2. RCM analysis team — a team of subject matter experts are assembled comprising employees and industry representatives (wood pole suppliers, other authorities, research bodies) to undertake the analysis.
3. Failure mode analysis — all the known and potential failure modes are identified. This generally includes identification of the following:
 - function of the asset
 - failure types
 - potential impacts of failure
 - potential causes of failure.
4. Maintenance policy developed — appropriate maintenance policies are determined for each failure mode to meet the required performance. This performance is generally expressed as an availability rate for the asset. The maintenance strategies include inspection frequencies, pole treatment frequencies (fungal decay), pole reinstatement, redesign, pole replacement and termite treatment.
5. Systems updated — the policy development/RCM process determines the frequency of inspections based on risk and economics. SAP (our corporate asset management system) then applies the policy rules to the poles to ensure that inspections take place with the right frequency based on that prioritisation. Prioritised inspections are automatically generated and notifications are created to undertake any required maintenance actions triggered during the inspection process.
6. Monitoring — performance of maintenance strategies are monitored such as defect and failure rates to ensure effective implementation and verification of expected outcomes. A further review may be undertaken should performance not meet expectation.

Maintenance and associated condition monitoring policies are reviewed periodically. When new assets are introduced into the network, existing maintenance and condition monitoring plans are reviewed to ensure coverage of the change or new plans are created as appropriate.

Maintenance plans, policies, tasks and work instructions are captured and managed in the SAP Maintenance Management system. The RCM rules are configured in SAP, which automatically generates time based work orders for inspection and maintenance planning.

As part of the Pole Management Improvement Program, a pole CBRM model is being established for implementation mid-2021 to enable a risk based asset management approach. This will result in proactive pole interventions on a risk justified basis when operationalised.

14.1.1 Location and timing of asset retirements

The location and the timing of the retirements of the high volume asset types is not available at the start of any planning year. The location of the asset is determined only once an inspection is carried out and if a defect is detected. The severity of the inspected defect will determine the maximum time that can lapse before action is taken.

14.2 Condition Based Risk Management (CBRM)

CBRM is a structured methodology that combines Powercor's engineering experience, asset information, environmental factors, operating context to define current and future condition, performance and to quantify consequence and risk of asset failure for network assets.

The CBRM methodology that Powercor uses has been developed by EA Technology and is integrated into Powercor's asset and investment planning software¹².

Powercor applies the CBRM methodology to the following asset classes:

- poles
- zone substation transformers and regulators
- zone substation and switching station switchboards
- zone substation and switching station circuit breakers
- protection relays
- low voltage circuit breakers
- ring main units.

Where applicable, new asset models are developed and implemented by Powercor to quantify and manage asset risk through prioritised interventions. The following models are currently under development.

- high voltage distribution cables
- distribution regulators

The CBRM process can be summarised by a series of sequential steps, which is set out below.

¹² Copperleaf Investment Planning and Management software

Table 14.2 Steps in the CBRM process

Step	Description
1	Define asset condition Health indices are derived for individual assets within different asset groups. Health indices are described on a scale of 0 to 10, where 0 indicates the best condition and 10 the worst.
2	Link current condition to performance Health indices are calibrated against relative probability of failure (PoF). The HI/PoF relationship for an asset group is determined by matching the HI profile with the relevant observed failure rates.
3	Estimate future condition and performance Knowledge of degradation processes is used to trend health indices over time. This ageing rate for an individual asset is dependent on its initial HI and operating conditions. Future failure rates can then be calculated from aged HI profiles and the previously defined HI/PoF relationship.
4	Evaluation of potential interventions in terms of PoF and failure rates The effect of potential replacement, refurbishment or changes to maintenance regimes can then be modelled and the future HI profiles and failure rates reviewed accordingly.
5	Define and weight consequences of failure (CoF) A consistent framework is defined and populated in order to evaluate consequences in significant categories such as network performance, safety, financial, environmental, etc. The consequence categories are weighted to relate them to a common unit.
6	Build risk model For an individual asset, its probability and consequence of failure are combined to calculate risk. The total risk associated with an asset group is then obtained by summing the risk of the individual assets.
7	Evaluate potential interventions in terms of risk The effect of potential replacement, refurbishment or changes to maintenance regimes can then be modelled to quantify the potential risk profile associated with different strategies.
8	Review and refine information and process Building and managing a risk based process driven by asset specific information is not a one-off process. The initial application will deliver results based on available information and crucially, identify opportunities for ongoing improvement that can be used to build an improved asset information framework.

In terms of the steps in the process:

- steps 1 to 4 essentially relate to condition and performance and provide a systematic process to identify and predict end-of-life. Future expenditure plans can then be linked to probability of failure and failure rates

- steps 5 to 7 deal with consequence of failure and asset criticality that are combined with PoF values to enable definition and quantification of risk
- step 8 is a recognition that building and operating a risk-based process using asset specific information is not a one-off exercise.

Each year, Powercor updates the data in its CBRM models as part of its budget submission process. Powercor reviews the outputs of the CBRM and identifies the projects that deliver the greatest risk reduction. The latter projects are determined by calculating the difference between the risk in a future year if the asset is not replaced and the risk that would result if the plant is replaced, and then assessing the various options to deliver the risk reduction.

While the CBRM methodology identifies a proposed year for the replacement of an asset, timing of the investment may change due to:

- risk reduction benefits of the project when compared to other projects
- alignment opportunities with augmentation projects for delivery synergies

14.3 Other methodologies

Condition-based monitoring and risk-based economic assessment is not possible or cost-effective for all types of plant and equipment. Some plant and equipment rely upon inspection cycles, similar to poles and wires, while others rely on age as the best estimate of condition. Some assets that do not directly impact the performance of the network, and for which the cost of implementing a condition-based or a risk-based approach outweighs the benefit, are run to failure. Other assets, such as surge arrestors, are designed to only be used once and are replaced upon use.

Details of retirement and replacement methodologies for these assets are set out in the relevant asset management plans, and explained in the next chapter.

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 2021 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 15.1 Planned asset retirements and de-ratings

Location	Asset	Project	Retirement date	2021 DAPR
Inglewood (IWD) Regulator Substation	IWD Regulator	Replacement	2025	2025
Robinvale (RVL) Zone Substation	Transformer 2	Replacement	2026	2026
Warrnambool (WBL) Zone Substation	Transformer 3	Replacement	2024	2024

Location	Asset	Project	Retirement date	2021 DAPR
Eaglehawk (EHK) Zone Substation	EHK CB A 66kV Circuit Breaker	Replacement	2025	2025
Geelong (GL) Zone Substation	GL CB A 66kV Circuit Breaker	Replacement	2026	2026
Geelong (GL) Zone Substation	GL CB B 66kV Circuit Breaker	Replacement	2026	2026
Geelong (GL) Zone Substation	GL CB C 66kV Circuit Breaker	Replacement	2026	2026
Ouyen (OYN) Zone Substation	OYN1 22kV Circuit Breaker	Replacement	2024	Not included
Ouyen (OYN) Zone Substation	OYN3 22kV Circuit Breaker	Replacement	2024	Not included
Ouyen (OYN) Zone Substation	OYN5 22kV Circuit Breaker	Replacement	2024	Not included
Ouyen (OYN) Zone Substation	OYN7 22kV Circuit Breaker	Replacement	2024	Not included

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 Eaglehawk (**EHK**) Zone Substation CB A 66kV Circuit Breaker

The Eaglehawk (**EHK**) zone substation is served by 66KV sub-transmission lines from Bendigo zone substation (**BGO**) in a loop with Bendigo terminal station (**BETS**).

The EHK zone substation is comprised of two 20/27 MVA transformers operating at 66/22kV connected to 66kV sub-transmission system with two line circuit breakers and one bus tie circuit breaker.

The CBRM analysis determined that the 66kV CB A bus tie circuit breaker has the current health index at 5.8 rising to 6.7 in next five years, and forecast require replacement in 2025.

Currently this circuit breaker is 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 the Powercor 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 the event of an oil filled circuit breaker failing catastrophically.

Powercor estimates that without the 66kV breaker A in service there will be 22.7 MVA of load at risk in 2025 and for 423 hours it would be unable to supply customers during a sub-transmission line fault.

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

- replace 66kV Bus tie Circuit breaker A at EHK for an estimated cost of \$0.43 million
- contingency plan to transfer load away via 22kV links to the adjacent zone substations of Bendigo Terminal Station 22 kV (**BETS22**), Bendigo (**BGO**), Kyabram (**KYM**), and Cohuna (**CHA**) up to a maximum transfer capacity of 17.6 MVA.
- Powercor's preferred option is to replace the 66kV bus tie circuit breaker A in 2025. The use of contingency load transfers will mitigate the risk should the asset fail ahead of its forecast replacement date.

15.1.2 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 5.5 rising to 6.1 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 \$1.22 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.

15.1.3 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 5.5 rising to 6.3 in next five years and is forecast to require replacement in 2026.

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 17.6 MVA of load at risk in 2026 and for 196 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 12.2 MVA.

Powercor preferred option is to replace the three 66kV bus tie circuit breakers A, B and C in 2026.

15.1.4 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 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 5.8 rising to 6.5 in next five years and is nonetheless forecast to require replacement in 2026. 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 2026 there will be 5.2 MVA of load at risk and for 42 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 2026. 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 5.2 MW at RVL zone substation would defer the need for this capital investment by one year.

15.1.5 Warrnambool (WBL) Zone Substation Transformer 3

The zone substation Warrnambool (**WBL**) is served by two sub-transmission lines from the Terang Zone Substation (**TRG**) and one from Koroit (**KRT**) zone substation and is comprised of two 25/33 MVA transformer and one 10/13.5 MVA transformers operating at 66/22kV. The transformer 3 has been in service for the last 71 years. This zone substation supplies the Warrnambool and surrounding areas.

CBRM analysis determined that the No.3 Transformer has a current health index of 5.5 rising to 6.4 in the next five years and is forecast to require replacement in 2024. Retirement of this transformer would require the remaining station load to be carried by the two remaining transformers and would place customers at risk of extended outages during times of unplanned network contingencies.

With the No3 transformer retired, Powercor estimates that in 2024 there will be 3.6 MVA of load at risk and for 25 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 WBL.

To address the anticipated system constraint at WBL 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 the adjacent zone substation of Koroit (**KRT**) up to a maximum transfer capacity of 9.4 MVA
- augment capacity by replacing the existing No3 66/22kV 10/13.5 MVA transformer at WBL with a larger 25/33 MVA unit for an estimated cost of \$3.8 million.

Powercor's preferred option is to replace the No3 Transformer at WBL in 2024. 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 attached System Limitation Report.

A demand side initiative to reduce the forecast maximum demand load by 3.6 MW at WBL zone substation would defer the need for this capital investment by one year.

15.1.6 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.

Powercor estimates that with a 22kV circuit breaker out of service, there will be 7.5 MVA of load at risk in 2024 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 the four 22kV feeder circuit breakers in 2024.

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:

- automatic circuit reclosers (**ACR**) interrupt fault current and automatically restore supply after a dead time in the event of a transient fault
- air-break switches (**ABS**) use air as an insulating medium to interrupt load current
- gas switches use SF6 gas as an insulating medium to interrupt load current
- oil switches use mineral oil as an insulating medium to interrupt load current
- isolators use air as an insulating medium to interrupt load current.
- 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 most¹³ switchgear assets in each year of the forward planning period in line with historical volumes for most assets. Line mounted Air-break switches are now replaced with gas switches in place of cyclic maintenance or defect repair activities which is above the historical replacement volumes. This change has been implemented to address key issues such as operational delivery inefficiencies and inability to maintain the assets due to equipment obsolescence.

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 sub-transmission 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

¹³ All switchgear with the exception of line mounted Air-break switches

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. No sub-transmission cables are planned for replacement due to condition in the next 5 year period.

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.

Powercor's planned volumes for underground cable replacements over the forward planning period are 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.
 - 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.
 - 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 Distribution plant

Powercor plans to replace distribution plant assets each year in the forward planning period. Distribution plant assets include a variety of assets listed below:

- HV Circuit breakers (22kV and 11kV) which are required to interrupt load or fault current are replaced based on the CBRM results, as explained in the previous chapter.
- 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. Some older kiosk transformers with integral oil RMU's are also being replaced due to safety concerns.
- Pole top capacitors are attached to the network to improve 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.

- Ring Main Units, which are banked switching units that enable switching between three or more underground cables, are replaced based on condition identified by scheduled inspection and defect reports, and then prioritised through risk and economic assessment.
- 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.
- 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.
- Combination switches, which are a high voltage switch and fuse combined, are replaced based on age with prioritisation of replacement determined by economic and risk assessment, given that neither the condition nor performance can readily be measured.

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**), Altona (**AL**), Ararat (**ART**), Ballarat North (**BAN**), Bendigo (**BGO**), Cobram East (**CME**), Corio (**CRO**), Echuca (**ECA**), Geelong B (**GB**), Geelong City (**GCY**), Geelong (**GL**), Laverton (**LV**), Mildura (**MDA**), Ouyen (**OYN**), Swan Hill (**SHL**), Shepparton North (**SHN**) and Winchelsea (**WIN**).
 - 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 15.4 Changes in timing of asset retirements / replacements and deratings

Proposed Asset Replacement	2021 DAPR	2022 DAPR
Koroit (KRT) Zone Substation CB B 66kV Circuit Breaker	2024	removed
Koroit (KRT) Zone Substation CB D 66kV Circuit Breaker	2025	removed
Portland (PLD) Zone Substation CB B 66kV Circuit Breaker	2025	removed

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 (**REFCLs**), 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

There was a regulatory test commenced by Powercor in 2018 for the REFCL Tranche 3 program.

Powercor has published a determination under clause 5.17.4(c) of the National Electricity Rules that there will not be a non-network option that is a potential credible option, or that forms a significant part of a credible option. The identified need is to comply with the Victorian Government’s requirement that REFCLs will be installed to meet the performance standard specified in the Regulations.

The RIT-D is for installation of REFCLs at the following zone substations for Tranche three by 1 May 2023 as shown in table 15.1 below.

Table 16.1 Current RIT-D projects

Project name	Description	Scheduled completion date
REFCL Tranche 3 Program	Construction of a new REFCL-protected zone substation at Gheringhap (GHP)	1 May 2023

There were no credible non-network options found to address the identified need, which is to comply with the Regulations. Also Powercor has not identified any other network options that would comply with the Regulations.

16.2 Future regulatory investment tests

The following projects are planned for future Regulatory Tests in the period 2023 through to 2027.

Table 16.2 Future RIT-D projects

Project name	Description	Scheduled start date
Bacchus Marsh (BMH) zone substation	Install 3 rd transformer, circuit breakers, 66kV/22kV works and control room	Jan 2024
Tarneit (TRT) zone substation	Establish new Tarneit zone substation and offload WBE, LV and TNA	Jan 2023
Winchelsea (WIN) REFCL and 3 rd transformer	Upgrade to Winchelsea to maintain ongoing REFCL compliance	Feb 2023
Eaglehawk (EHK) REFCL and 3 rd transformer	Upgrade to Eaglehawk to maintain ongoing REFCL compliance	Feb 2023
Ballarat East/West (BAE/BAW) zone substation	Establish new Ballarat East or West zone substation and associated 66kV/22kV works to maintain ongoing REFCL compliance in the Ballarat area	Sep 2022

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 one minute or less. SAIFI is expressed per 0.001 interruptions
- Momentary average interruption frequency index (**MAIFI**): 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 2021.¹⁴ Powercor reported to the AER its 2021/22 Financial Year performance against those targets in the 2021/22 Financial Year Regulatory Information Notice (**RIN**), and these figures are included in the table.

¹⁴ 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	47.073
	SAIFI	0.823	0.597
	MAIFle	1.200	0.984
Rural Short	SAIDI	104.142	85.757
	SAIFI	1.147	0.963
	MAIFle	2.508	1.785
Rural Long	SAIDI	240.916	197.488
	SAIFI	2.025	2.460
	MAIFle	4.393	2.904

In 2021/22 FY, Powercor achieved its targets for all 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:

- undertaking the various routine asset management programs, including:
 - inspection of nearly 180,000 poles and pole tops
 - maintenance and replacement programs for overhead and underground lines, primary plant (for example, Powercor replaced a number of circuit breakers, 66kV transformer bushings and current transformers) and secondary systems (such as replacement of ageing protection relays at zone substations)
 - 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 indoor 22kV switchgear in Zone subs. including several continuous on line monitoring systems
- 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
- 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
- trialling of new technologies such as fuse savers to assess and evaluate any improvement in the reliability outcomes
- conduct fault investigations of significant outages and plant failures to understand the root cause, in order to prevent re-occurrences
- 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 2021/22 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:

- voltage, including measuring customer voltage and network voltage using AMI data
- harmonics.

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 variations¹⁵

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%	Phase to Earth +50%, -100%	6 kV peak
2**		+ 13% - 10%	- 10%	Phase to Phase +20%, -100%	
3	1 – 6.6	± 6% (± 10% Rural Areas)	± 10%	Phase to Earth +80%, -100%	60 kV peak
4	11			Phase to Phase +20%, -100%	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).

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 2021-22 financial year, although many of these instances would have occurred from abnormalities or transients in the system.

¹⁵ Table 2 Clause 20.4.2 of the Victorian Electricity Distribution Code of Practice.

Table 17.3 Zone substation voltage variations in 2021-22 FY

Voltage variations	Number of occurrences
Steady state (zone substation)	6640
One minute (zone substation)	36
10 seconds (zone substation) Min<0.7	508
10 seconds (zone substation) Min<0.8	251
10 seconds (zone substation) Min<0.9	997

Powercor responds quickly to investigate and resolve voltage issues. The issues may be identified through the system monitoring undertaken by Powercor or as a result of customer complaints. The Supply Quality team may subsequently carry out projects to address concerns relating to voltages.

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
- installation of additional reactive power compensation, such as capacitor banks, to improve voltage performance.

Powercor may also identify issues with voltage 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 or harmonic constraints relating to proposals, with recommendations for corrective action provided to the party seeking to connect.

17.2.2 Customer voltage performance at low voltage

AS 61000.3.100 (as referenced in 16.2.1) 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

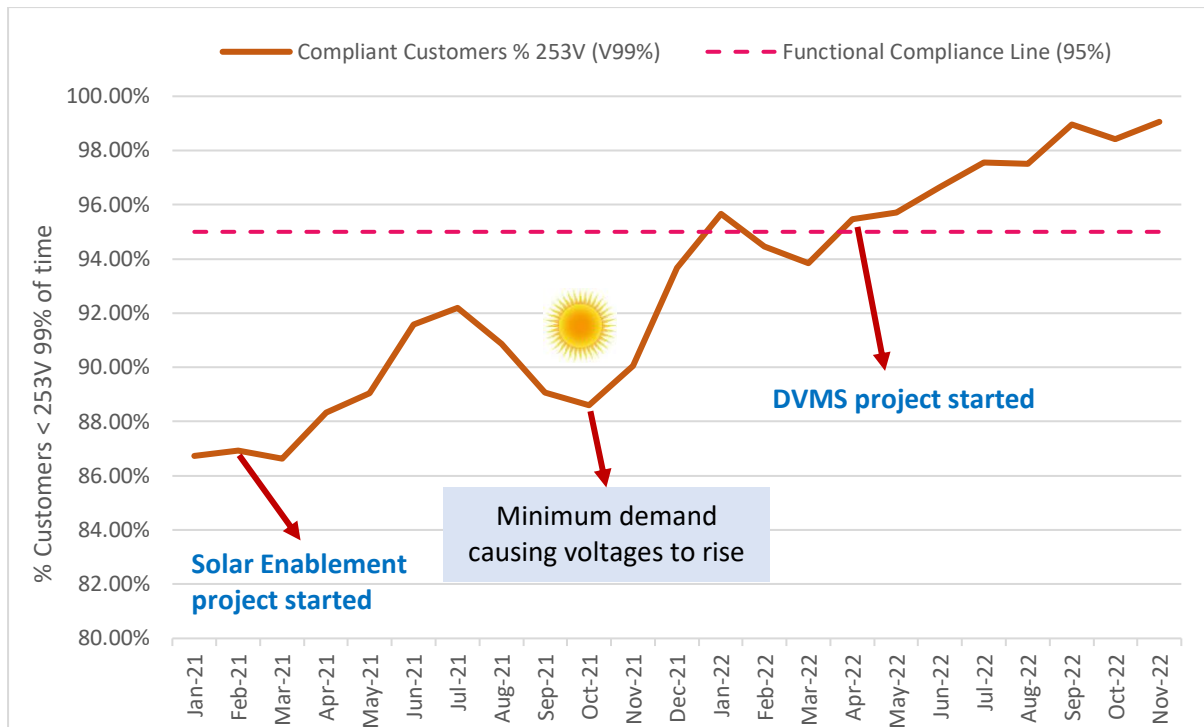


Figure 17.2 Monthly V1% customer voltage performance at low voltage

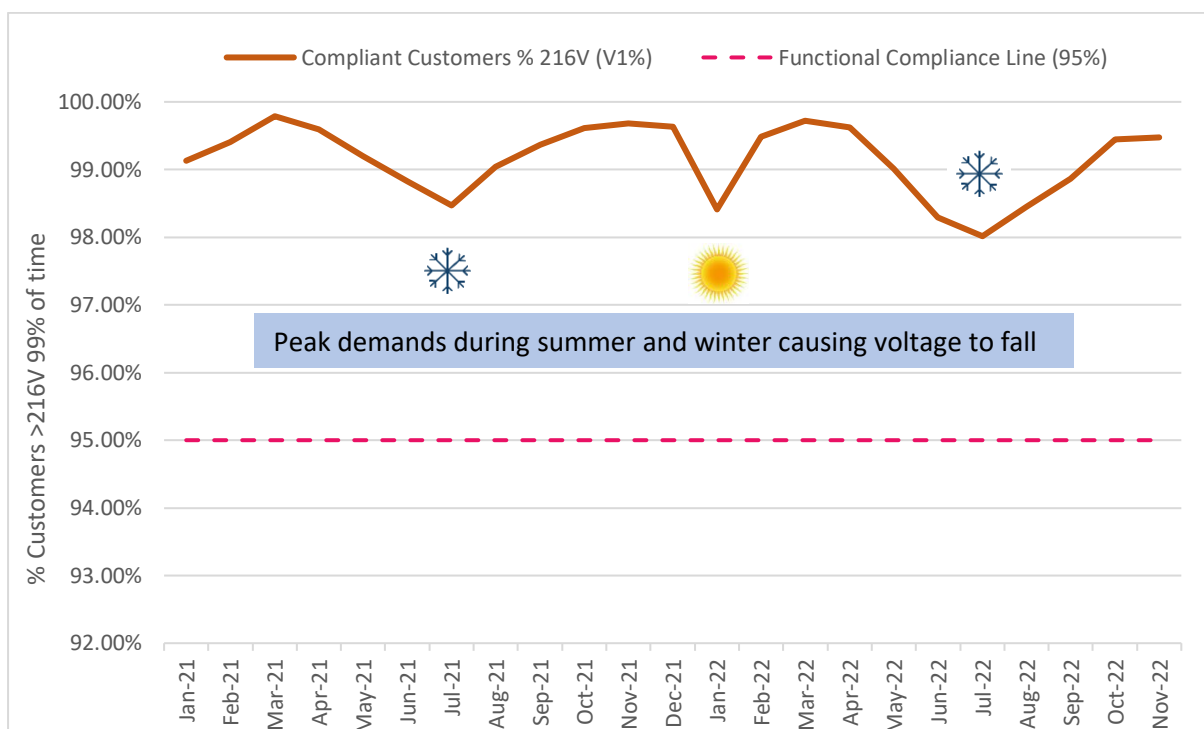
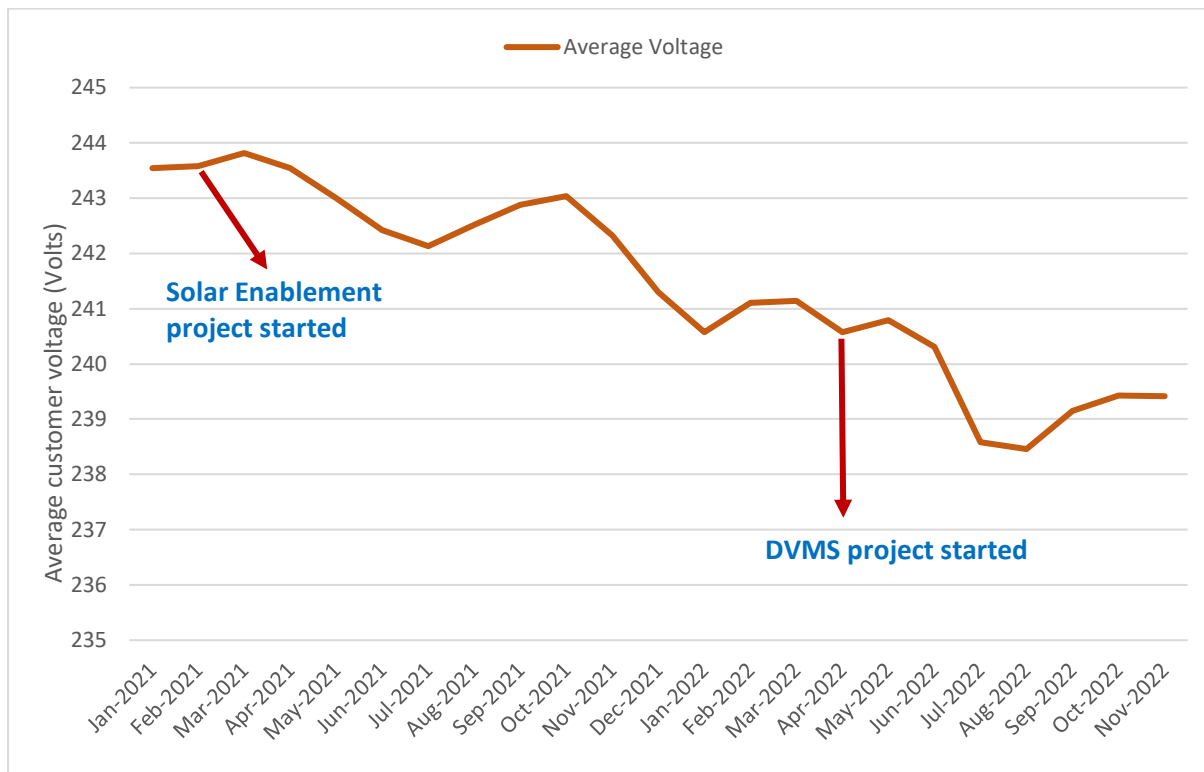


Figure 17.3 Monthly average voltage during 2021-22



As noted in Section 3.7, Powercor has undertaken numerous steps to improve customer voltage and have significantly increased works in 2022 through the solar enablement and DVMS programs. As a result, V99% performance has demonstrably improved year-on-year (i.e. comparison of June 2021 vs. June 2022). 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. As illustrated in Figure 17.3, the average voltage levels on the networks are also continuing to decline over the time towards the standard voltage (230V).

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/UaPnYl6yeV>

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 Harmonics

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 %.					

Powercor responds quickly to investigate and resolve voltage issues. The issues may be identified through the power quality meters that Powercor has installed to monitor the quality of supply or as a result of customer complaints. The Power Quality team may subsequently carry out projects to address concerns relating to voltages.

Where the voltage harmonics are measured to be consistently outside of the required levels, Powercor will investigate and resolve the issue. The solutions that Powercor may adopt include:

- alter the switching sequencing of the network equipment to reduce the voltage harmonic distortions
- replacing small sized conductors with large conductors in order to improve the voltage harmonic performances
- installation of harmonic filtering equipment to improve voltage harmonic performance or
- action against large customers or generators who have been found to be the cause of voltage harmonic issues.

Powercor may also identify issues with harmonics 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 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 2022 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 2021.

Table 18.1 Summary of embedded generation connections

Description	Quantity (>5 MW)
Connection enquires under 5.3A.5	2
Applications to connect received under 5.3A.9	7
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	1,569
Applications to connect received under 5A.D.3	332

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.
- Due to the constraints associated with low system strength on the transmission network in the West Murray Zone (WMZ) extending across parts of Victoria and New South Wales, the assessment of large-scale generator connections in the area have to be done sequentially as per AEMO sequencing approach for uncommitted projects and takes longer than normal due to complexities of the advanced detailed modelling and analysis.

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 2022/23 the following details some of Powercor activities:

- Powercor has communicated with providers of demand management and embedded generation services to explore potential non-network options
- Powercor is presently involved with the development of a number of embedded generation projects at various stages. Powercor is presently involved with the development of a number of embedded generation projects at various stages. Powercor has recently commissioned 18 MW of embedded generation in 2022, making a total of 1387 MW of installed capacity. In addition, there are 15 approved projects totalling 314 MW in development
- Powercor monitors industry developments and engages with providers of demand management and smart network technologies
- In 2021, Powercor trialled a residential demand management program for customers to voluntarily reduce demand and be rewarded during peak periods on specific distribution substations in the network. 535 customers registered to the program, which represented an uptake rate of 6% from customer base of 9,654. Powercor called 6 events and yielded total energy reduction of 4.5 MWh. This program is complemented by 'Energy Partner' program initiated in 2020 which allows us to directly control participating customers' air-conditioning load. Powercor is open to collaborate with partners who can add value to the programs from customer experience perspective while delivering network benefit cost-effectively.
- Powercor led a feasibility study, in partnership with 12 community energy groups and local councils, CitiPower and United Energy, and supported by the Department of Environment, Land, Water and Planning (DELWP) through the Neighbourhood Battery Initiative (NBI) program. This study aimed to identify opportunities for neighbourhood batteries and develop supporting information to assist community

groups who are looking to explore a neighbourhood battery project. The outcomes of the study included the proposal of a potential program of battery projects to DELWP, the '[Powerful Neighbours Report](#)' a comprehensive guideline for future battery projects as well as a [series of animations](#) to improve community and customer understanding of neighbourhood batteries.

- Through the feasibility study it was also identified that there is an interest from community energy groups, local councils, research organisations and DELWP in having a greater understanding of their local distribution network. Investigation has commenced regarding how this information may be shared with these stakeholders, with a prototype network visualisation tool being trialled with NBI partners. This mapping tool would also be able 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.

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 Department of Environment, Land Water and planning (DELWP).

Tarneit Battery is a 120KW/360KWh ground-mount three phase 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 is planned to be commissioned in December 2022.

18.4 Demand side engagement strategy and register

Powercor updated and published its Demand Side Engagement Strategy in July 2019. The strategy is 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 2021, no formal submissions from non-network providers were received however there are a total of 162 registered entities.

19 Information Technology and Communication Systems

This chapter discusses the investments we have undertaken in 2022, or plan to undertake over the forward planning period 2023-2027, relating to information technology (IT) and communications systems.

19.1 Security Program

With a continuously evolving cybersecurity threat landscape, we continue investing in our cyber capabilities to enable us to protect our network and our customers. Our on-going cyber security program of works introduces increasingly sophisticated processes and systems that proactively prevent, detect, respond to, and recover from security threats that have the potential to disrupt the operation of the distribution network and our services.

Through our Cybersecurity strategy, we have delivered uplift programs to email, identity and cloud security. We have also completed a transformational program to uplift our 24 x 7 Security Operation Center (SOC) as well as our Security Incident and Event Management (SIEM) system.

Our 2023 program will continue to deliver on further maturing our web, identity, and operational technology (OT) cybersecurity posture.

Our current cyber security strategy will be fully delivered by 2025. We will continue to align our security strategy and initiatives with 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. Our program of work will meet the compliance requirements for the Security of Critical Infrastructure Act (SOCI) 2018 and the associated Risk Management Program (RMP) Cyber and Information Security Hazard rules.

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 2022, we began 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
- 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.

During the forward planned period for this DARP 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, map the LV model for improved safety outcomes and LV data quality.
- Market system upgrade – uplift capability of market systems applications, which support market transitions and data to be provided to the market

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.

This year we implemented Phase 2 of the five-minute settlement program which included:

- 1) preparedness and readiness for the installation of 5 minute enabled meters by 1 December 2022,
- 2) ensuring AMI meter fleet installed after 1 December 2018 are configured to collect and send data in 5 minute intervals by 1 December 2022. Key Phase 2 changes include:
 - Upgrading of all key metering applications to be five-minute settlement compliant
 - Ensure all required meters are collecting, storing and processing data in five minute intervals

This wider 5MS program, included enhancing storage to handle significantly more data and changes to system architecture (e.g. Market Transaction System, Itron Enterprise Edition, CIS/OV, UIQ, Salesforce, SAP) as well as business and operational processes (e.g. billing, contract centres, reporting, network, advanced metering infrastructure (AMI) operations and network analytics).

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 3.7 procedure changes to improve communication between market participants
- Improve our MSATS Standing Data in line with the determination arising from AEMO's MSATS standing data review
- Update our systems to facilitate AEMO's Global Settlement approach for retail market settlements
- 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

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 2022 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 the deployment of a new storage array, which will accommodate our projected data volumes in a more cost effective fashion is approximately one tenth the physical footprint of the current device
- Deployed dedicated infrastructure for the Network Analytics Platform, which is designed to support a more efficient and safe network for our customers
- Refreshed critical network infrastructure to ensure we were on a fully supported solution, have the capacity to accommodate increasing network traffic volumes and ensure that our network devices are able to have security patches applied to protect against cyber attacks
- Upgraded server infrastructure to ensure that we are on a fully supported solution, have the capacity to accommodate increasing application demands and ensure that our servers are able to have security patches applied to protect against cyber attacks

- Upgraded our Netscaler load balancer solution to ensure that we are on a fully supported solution, and ensure that the solution is able to have security patches applied to protect against cyber attacks
- Completed the rollout of Office 365 to all users to enable more users to work remotely without requiring a Citrix or VPN SSL remote access solution
- Completed the rollout of a new Windows 10 image, including providing new laptop devices to many users. The new Windows 10 solution includes an "always on" VPN solution to seamlessly connect to simplify the remote working experience.

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

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

Outage communications is one of the most important services we provide to customers. In 2022, we improved the planned outage notification process for our customers, including providing more options around the mediums for communication to better reflect our customer preferences. The initiative included the implementation of a new customer portal design as a virtual front counter that is destined to become a single log-in one stop shop for customers to access our online services. These improvements were reflective of the Essential Services Commission's final decision on the Electricity Distribution Code requirements in relation to planned outages.

In 2022 we also completed the following key technology initiatives:

- We digitised the capturing of customer reported faults; tracking of progress and rectification of these. This improves the user experience as customers are kept informed of the progress and closure of their claim.
- We enabled customers to track the end to end project status of their augmentation project and/or no go zone enquiries. This provided customers will more accurate and up to date information on the status of their project, allowing for more informed decisions to be made
- We enhanced and expanded our solar pre-approval tool, rapidly increasing speed at which customers can obtain pre-approval for solar exports. This provides customers increased certainty and accuracy relating to their request for solar export and other customer energy resources

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.

In 2022 we continued to grow the use of our enhancement to the Distribution Management System to actively manage network constraints resulting from solar or wind generators connected to our high voltage network. This has allowed more generation to be included in the distribution network and speed the decarbonisation of our energy sources.

The implementation of a strategic network analytics capability in 2021 has allowed us to implement in 2022 an active and dynamic voltage management solution which allow greater uptake of rooftop solar whilst maintaining system security on high demand days.

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

Part of the digital revolution is being able to provide more information on how the electricity network is performing in more usable formats. In 2022 we trialled making network performance information available to a selected set of trial external users using a visualisation tool that is used within the business.

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
- Implement a first generation operational forecasting capability along with a complete digital network model from Terminal Station (transmission connection) to the customer connection
- Expand the visualisation of network performance to more community groups and entities

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 2022 we have completed works on the following:-

- Full Retirement of 38 aging narrowband 900MHz Point to Multipoint (P-MP) Radio systems, and replacement with new 450Mhz Ethernet radio links with improved reliability, robustness and with real time performance monitoring and reporting
- Commenced selection of MPLS technology to ease capacity issues on some sections of Powercor's optical fibre network
- Initiation of the replacement of 10 aging 400MHz P-MP and PtoP narrowband Radio systems with new 450Mhz Ethernet radio links with improved reliability, robustness and with real time performance monitoring and reporting
- 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
- Commenced 3G device replacement with new 4G technology introducing ISO55001 Asset Management functionality with centralised and remote configuration management and real time performance monitoring and reporting
- Work closely with other Victorian DNSPs to leverage and share respective fibre network facilities to expand the business fibre network deployment footprint cost effectively to retire selected radio network links and improve communications reliability.

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 (**ACRs**), 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 18.6 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 overblown fuses—improving phase balancing, which will allow greater asset utilisation (and therefore reduce augmentation) as well as avoiding replacement expenditure from blown fuses

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.

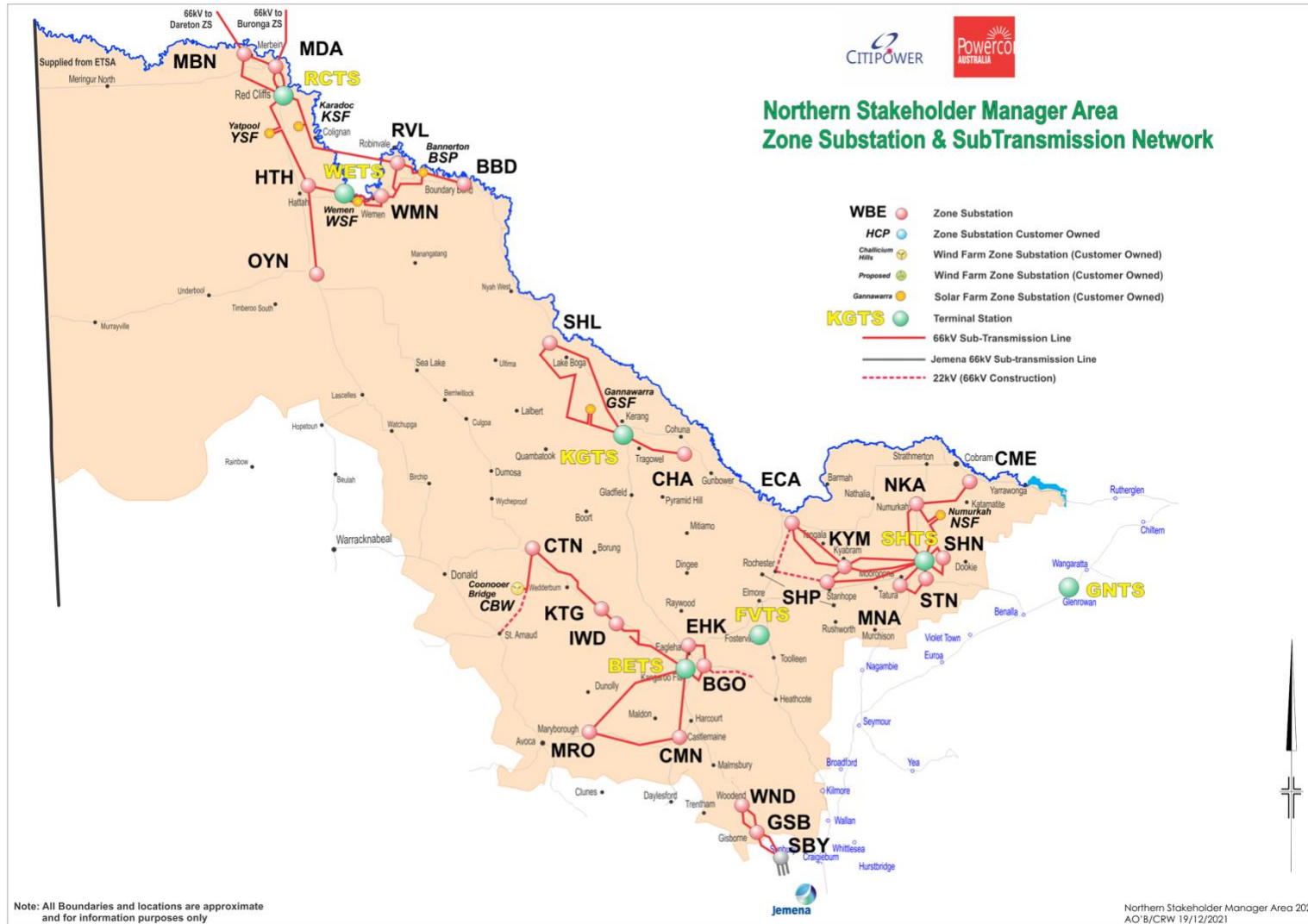
AMI meters also allow us to monitor basic power quality levels at individual customer premises. We have developed query and reporting tools to aggregate the data into meaningful sets of information and provide exception reporting to better manage the quality of supply to customers such as steady-state 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.

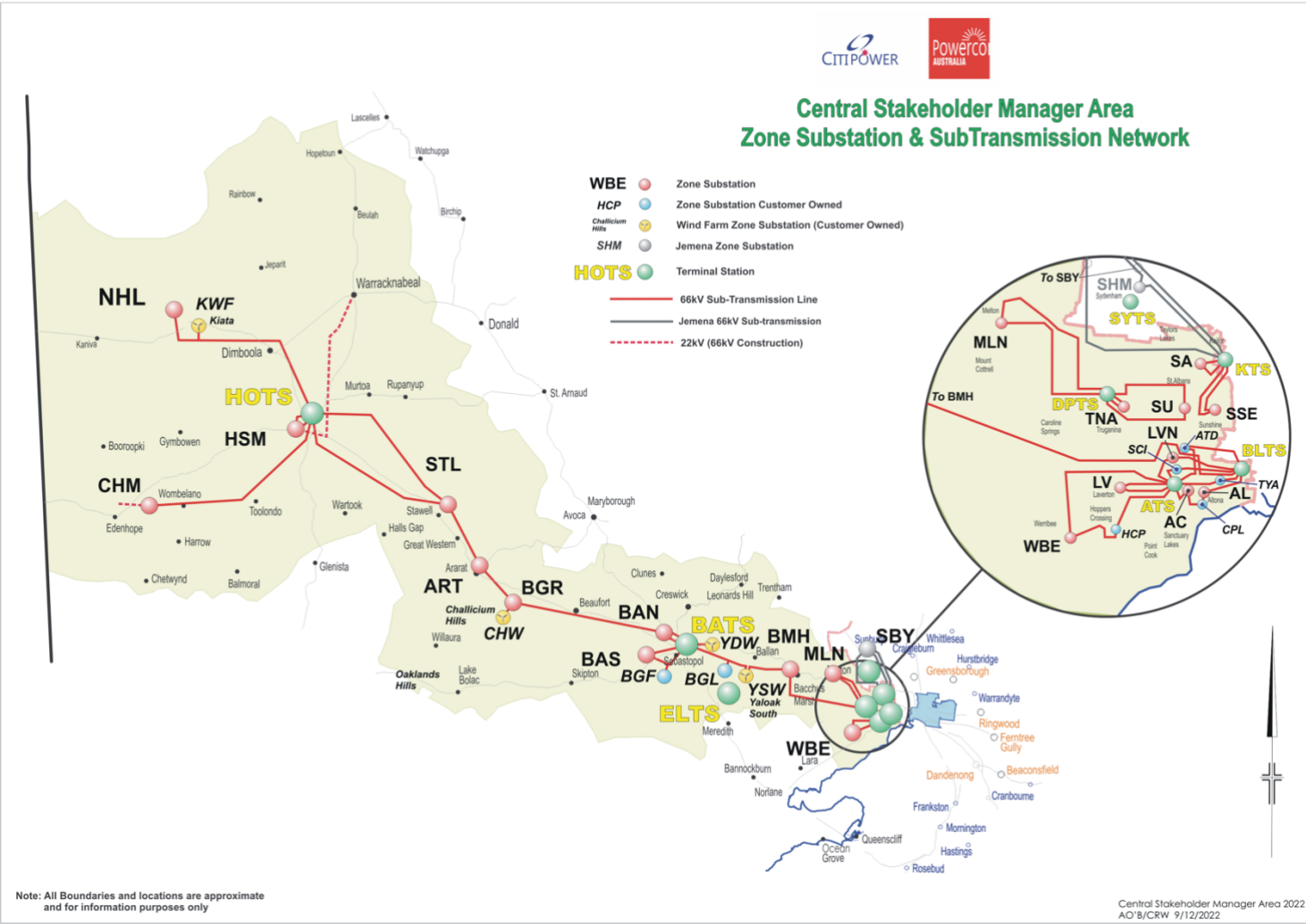
There is also improved quality of information and customer services during outages. We have developed an Interactive Voice Response service and SMS service which automatically advises customers of outages identified in a timely way through the last gasp AMI function. This has contributed to high levels 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

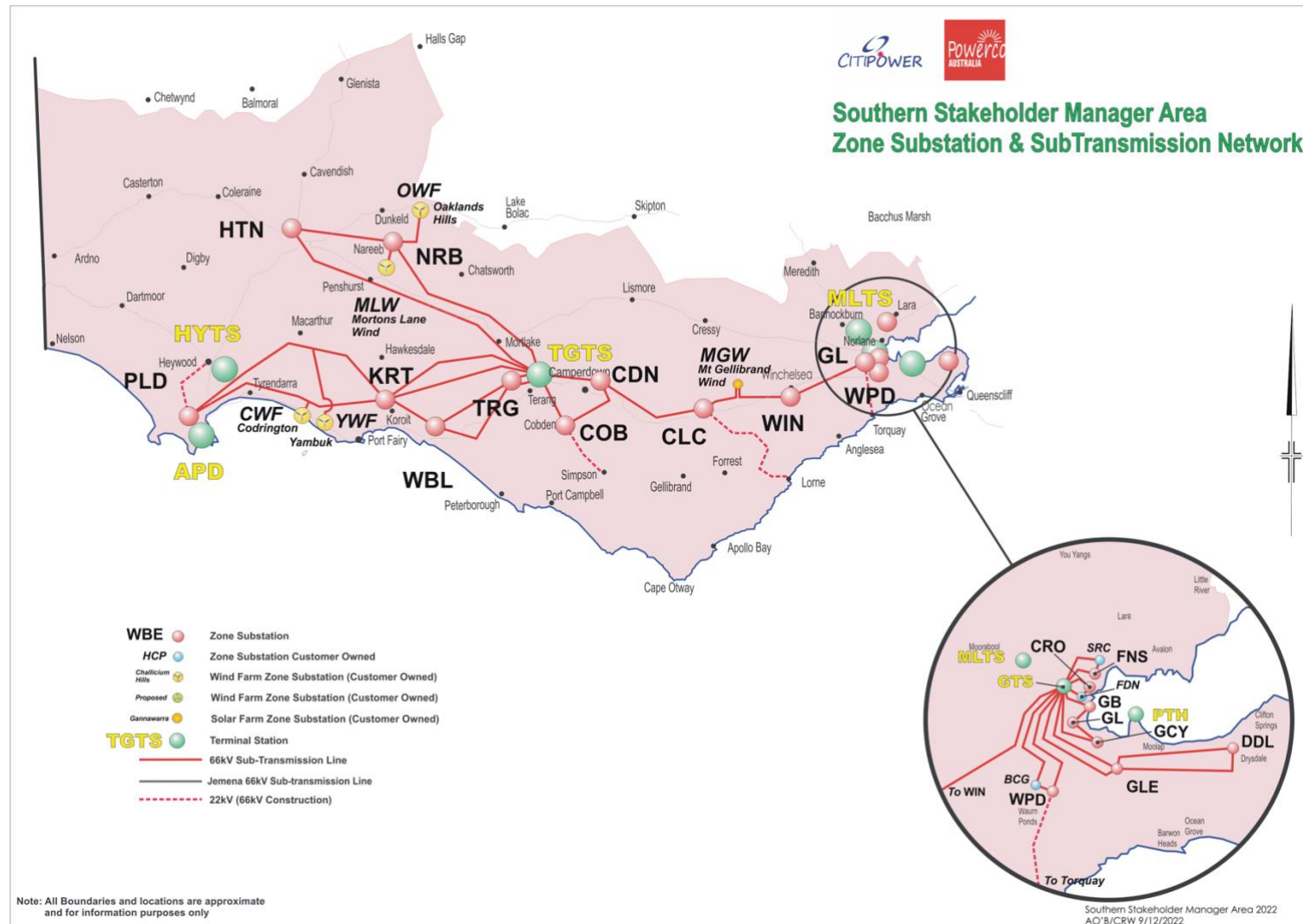
A.1. Northern area zone substation and sub-transmission lines



A.2. Central area zone substations and sub-transmission lines

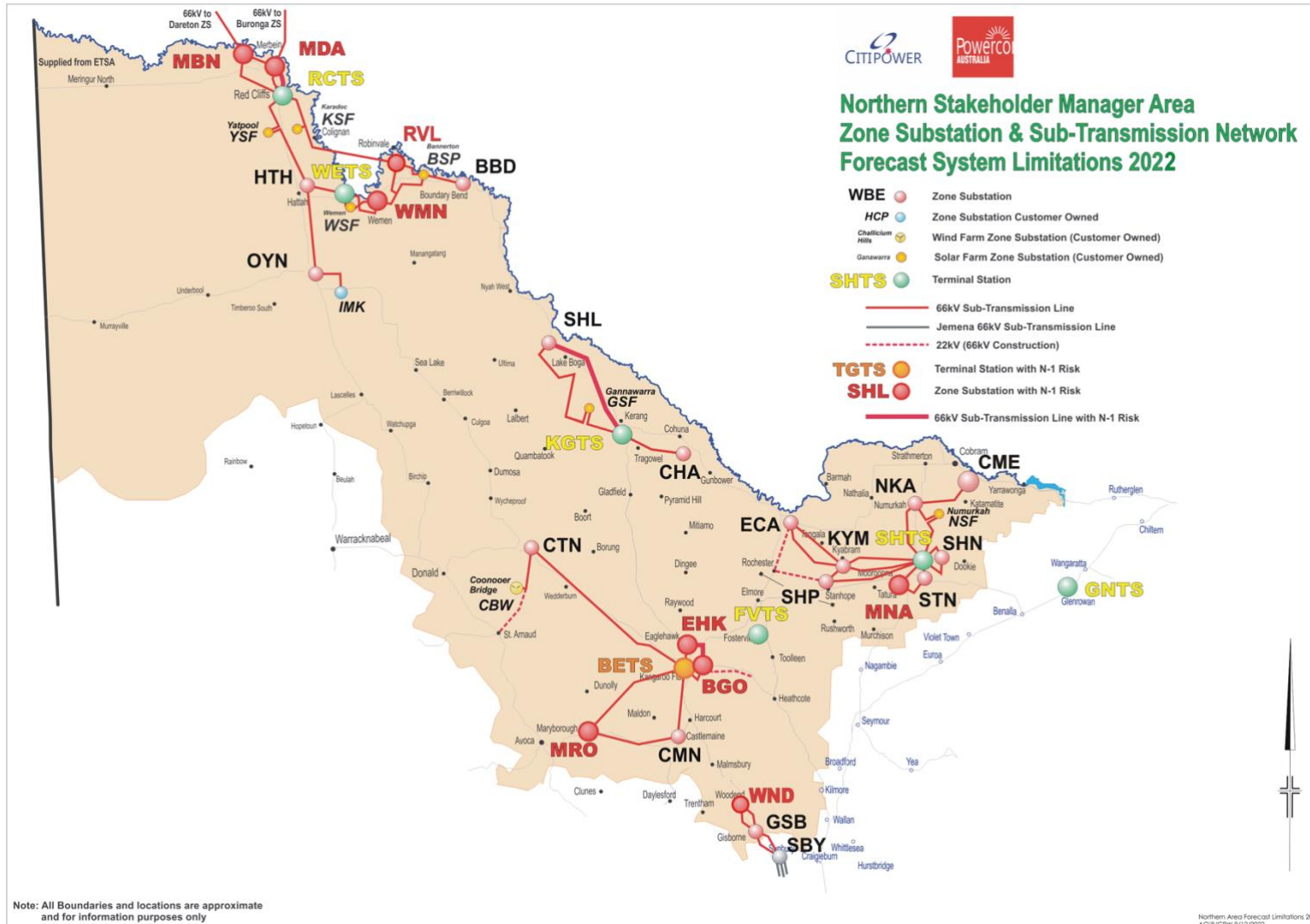


A.3. Southern area zone substations and sub-transmission lines

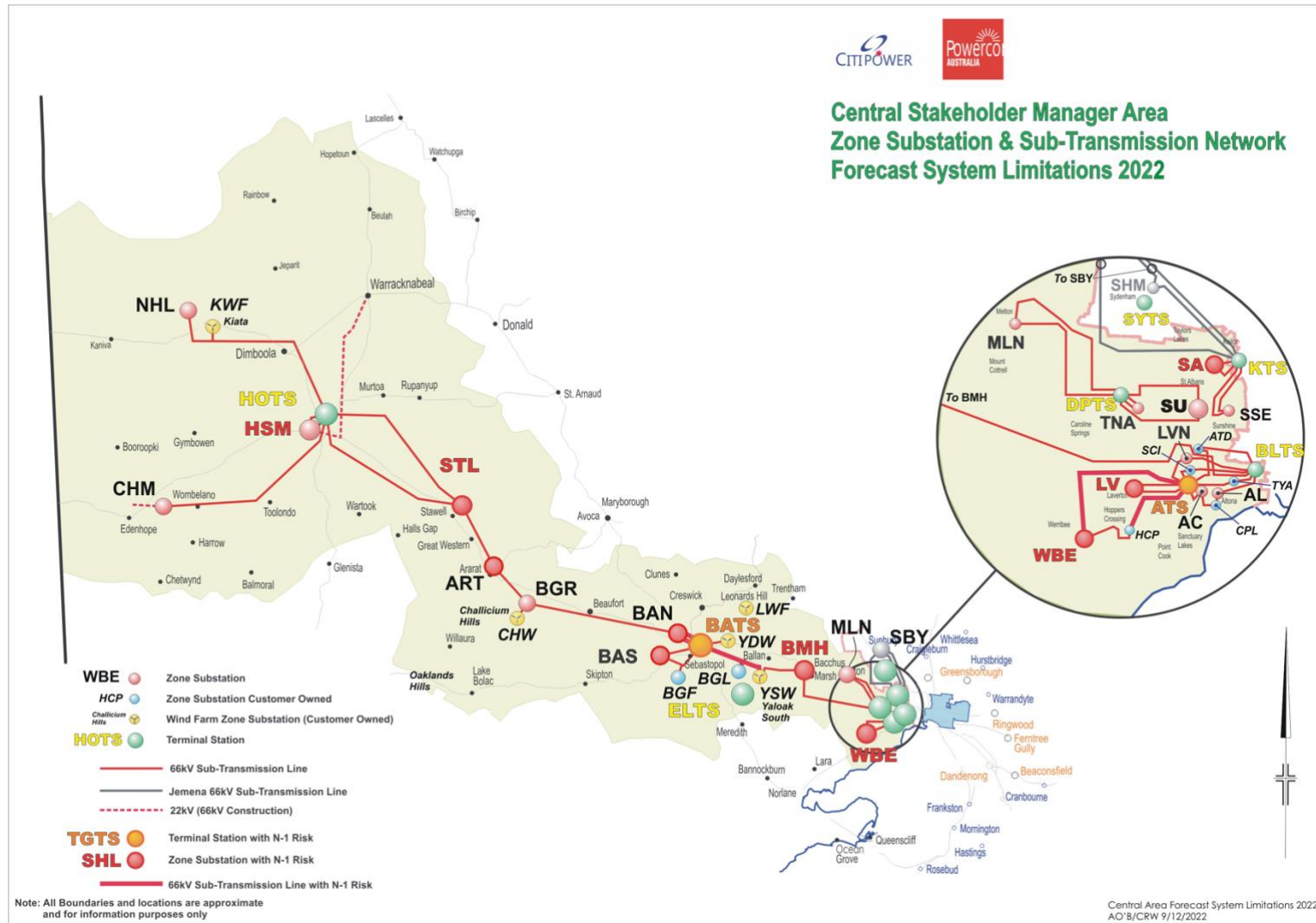


Appendix B Maps with forecast system limitations and asset to be retired or replaced

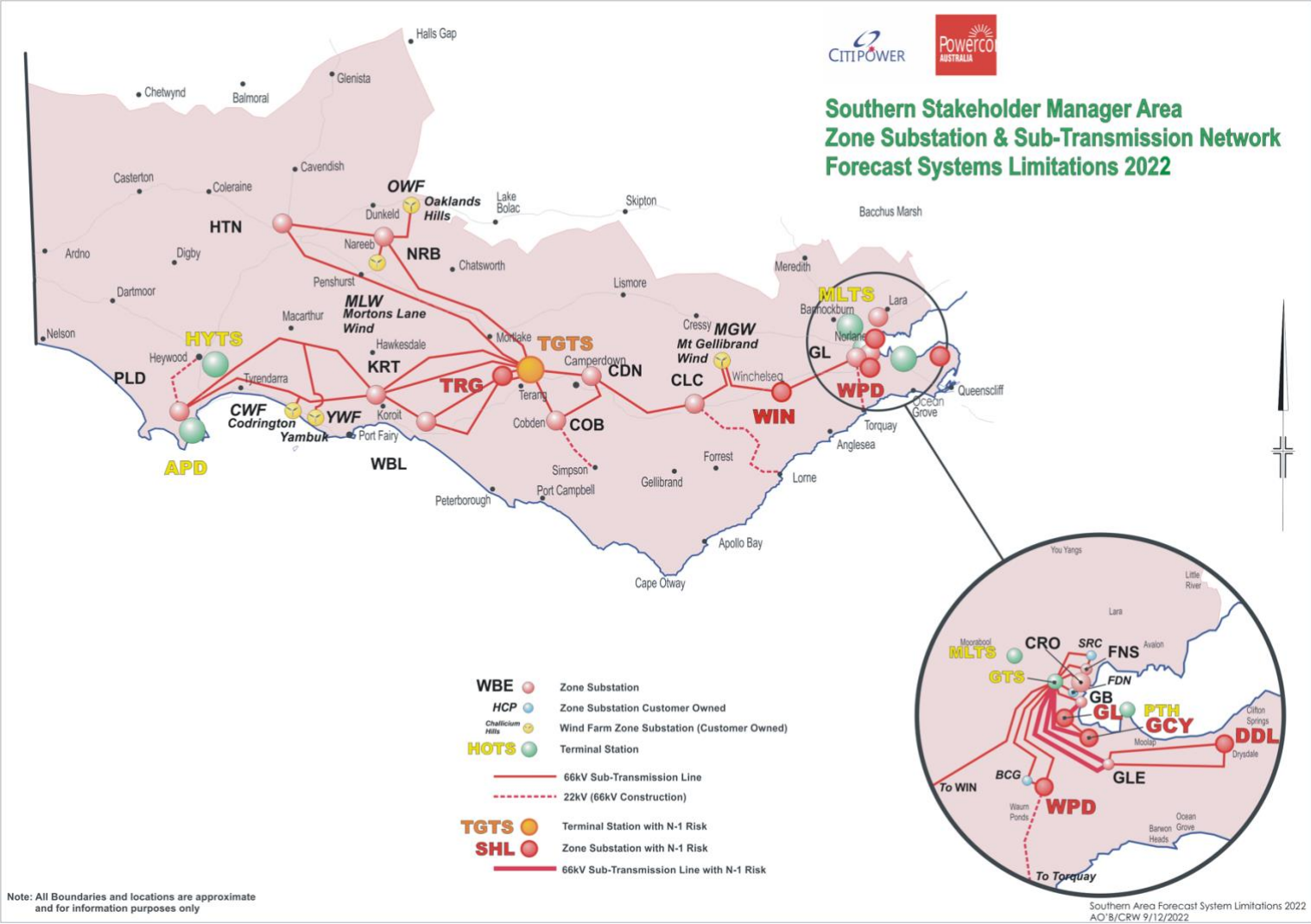
B.1. Northern area map with forecast system limitations



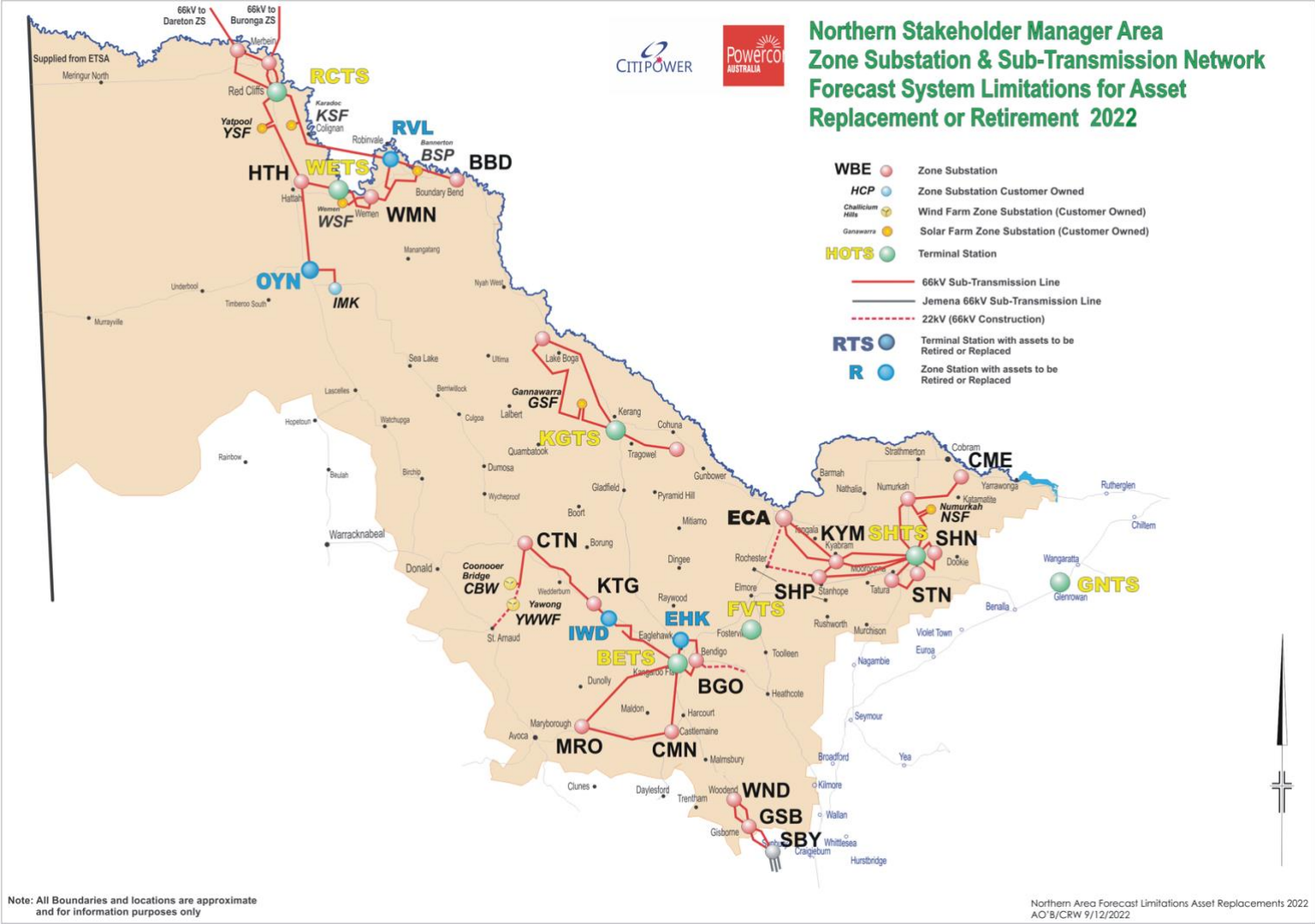
B.2. Central area map with forecast system limitations



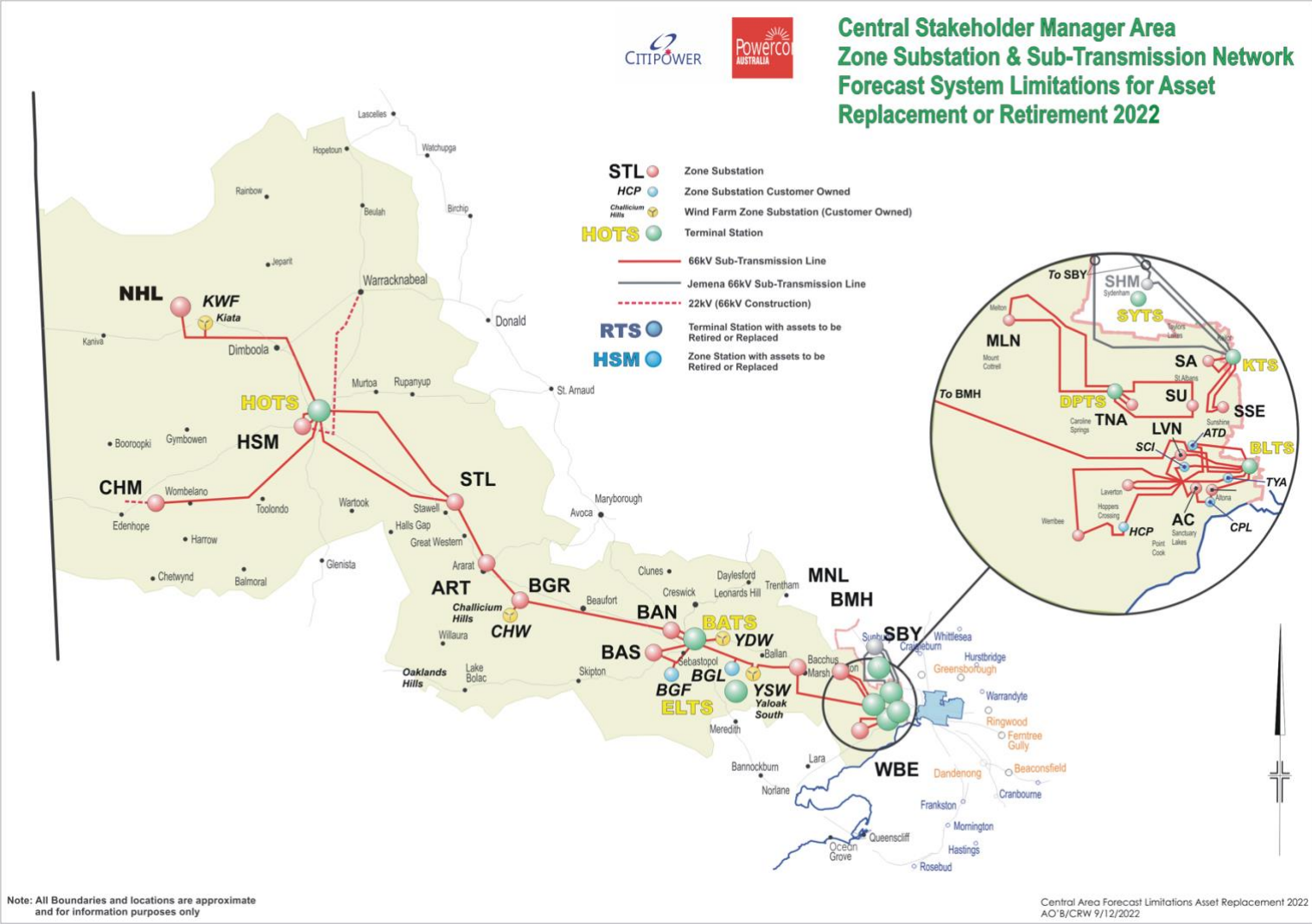
B.3. Southern area map with forecast system limitations



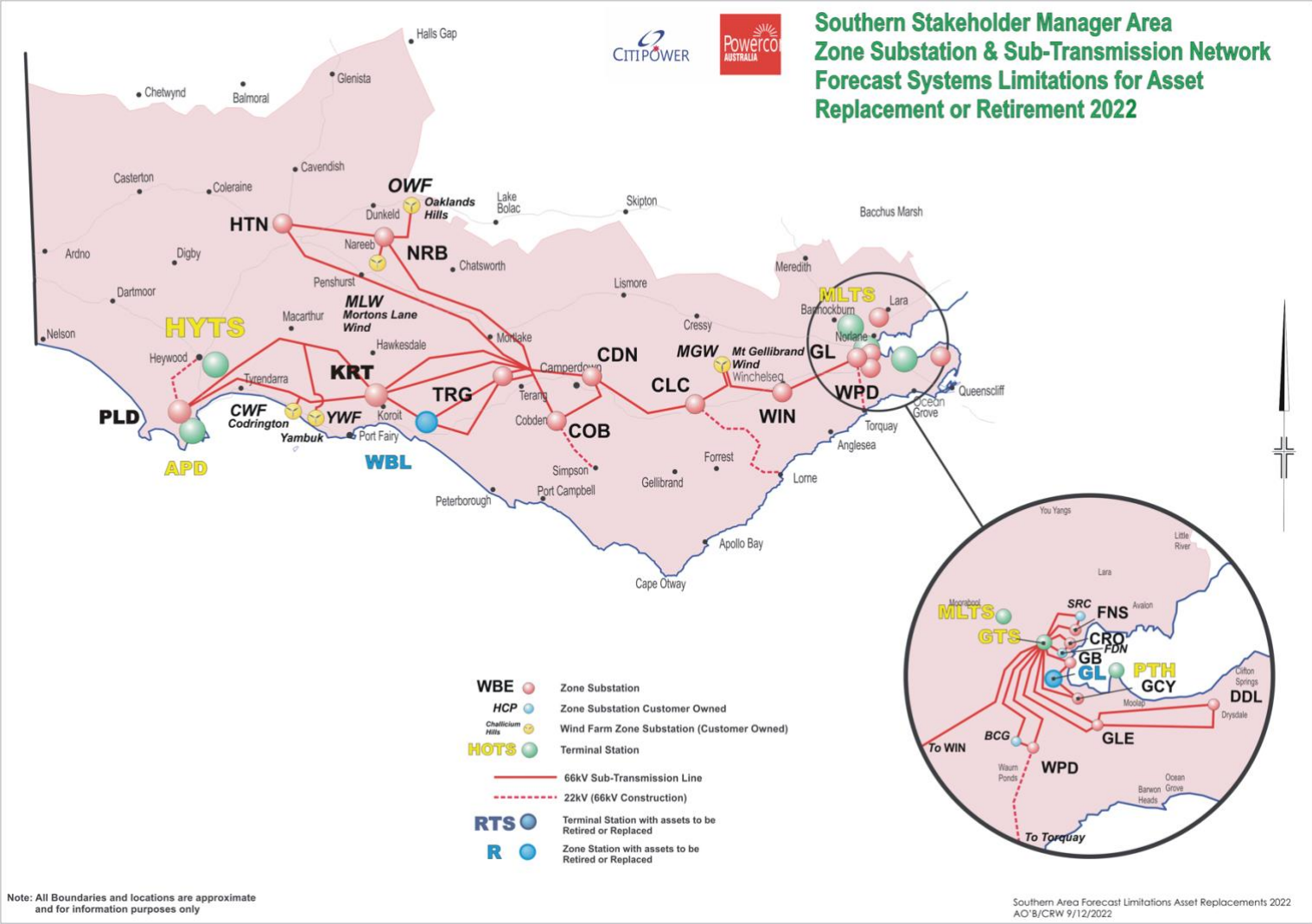
B.4. Northern area map with assets to be retired or replaced



B.5. Central area map with assets to be retired or replaced



B.6. Southern area map with assets to be retired or replaced



Appendix C Glossary and Abbreviations

C.1. 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 50 th 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.2. 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	TRG	Terang
GCY	Geelong City	WBE	Werribee
GL	Geelong	WBL	Warrnambool
GLE	Geelong East	WIN	Winchelsea
GSB	Gisborne	WMN	Wemen
HSM	Horsham	WND	Woodend
HTN	Hamilton	WPD	Waurin Ponds

C.3. 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

Appendix D Asset Management Documents

Powercor document references are:

Asset Management Policy: JEQA4UJ443MT-150-27559

Asset Management System Framework: JEQA4UJ443MT-150-27597

Strategic Asset Management Plan: JEQA4UJ443MT-150-27604

Asset Management Strategies subjects – the following table lists the asset management strategies that apply across all asset classes:

Asset management strategy subject	Purpose
Network Operations and Utilisation	Structured approaches to improvements to a range of operational functions which together improve operational performance of the network.
Asset Information and Systems	Asset data and information types, relationships between them and the systems used to manage asset data and information.
Network Performance	Performance improvement programs to meet network reliability and performance requirements over the regulatory period, and an increasingly complex generation and distribution landscape requiring sophisticated technical responses from CP/PAL
Bushfire Mitigation	Structured approaches to prevention of bushfires associated with the design, operation, construction and maintenance of network assets.
Vegetation and Line Clearance (<i>planned for future</i>)	Integration of vegetation and line clearance requirements into the asset management system to align with asset management objectives and ensure ongoing regulatory and statutory compliance.
Connections, Augmentation and Replacement	Improvement programs to manage the connections, augmentation and replacement processes to ensure the network remains capable of distributing a reliable supply of electricity to customers
Maintenance Management	The rationale behind various maintenance management initiatives, projects and plans that together ensure the right maintenance is delivered at the right time and in the right way.
Network Safety	Integration of network safety practices into the asset management system to ensure visibility of regulatory and statutory compliance obligations, and alignment with asset management objectives.
Future Grid	Technologies and smart networks (including batteries, solar and wind generation, decentralised generation, demand management, metering, demand management) and associated impacts on network design, dynamics, monitoring and corresponding changing skill requirements.
Environment and Sustainability (<i>planned for future</i>)	Integration of environment and sustainability requirements into the asset management system to ensure visibility of regulatory and statutory compliance obligations and alignment with asset management objectives.
Asset Management System Performance (<i>planned for future</i>)	Description of the strategies and objectives that CP/PAL use to measure asset management system performance, and ensure optimum asset management system effectiveness, efficiency and continued alignment with the SAMP objectives.
Asset Management System Resources (<i>planned for future</i>)	The assessment, selection, development, procurement or acquisition, deployment and application of human and non-human resources required to develop and implement the CP/PAL asset management system, and implement and monitor the asset management objectives.

Asset Class Strategies – the following table lists the asset class strategy subjects and the asset coverage of each strategy:

Asset class strategy	Asset coverage
Poles and towers	Wood, concrete, and steel poles Steel lattice towers
Pole top structures	Pole top structures including crossarms and insulators HV fuses Surge arresters
Overhead conductors	Bare conductors (aluminium, copper, steel) High voltage aerial bundled cable Low voltage aerial bundled cable Covered conductor
Underground cables	Subtransmission, high voltage and low voltage cables Cable pits Cable pillars Auxiliary services Cascade LV lighting cables
Zone transformers	Zone substation transformers, regulators and autotransformers Transformer bushings Transformer tap changers Transformer water cooling systems
Distribution substation plant miscellaneous	Regulators Capacitors Capacitor balancing units
Public lighting	Luminaires PE cells Brackets
Zone substation plant miscellaneous	Capacitor banks Capacitor bank step switches Reactors Static VAR compensators Instrument transformers Surge diverters Steel work Fire walls Neutral earth resistors (NER) Rapid earth fault current limiter (REFCL) systems Direct current (DC) supply systems Station low voltage (LV) supply systems
Distribution transformers	Pole transformers Kiosk transformers Ground transformers Indoor transformers
SCADA and communications	Optic fibre cable Supervisory cable Digital microwave radio Cellular radio Voice over IP (VoIP) system RTUs

Asset class strategy	Asset coverage
Zone switchgear	Circuit breakers Switchboards Outdoor busses Switches
Protection and control	6.6kV, 11kV, 22kV, 66kV and zone substation protection schemes and relays Line and feeder protection schemes Bus and station protection schemes Transformer protection schemes Cap bank protection schemes
Property and facilities	Zone substation buildings Zone substations leases Non kiosk ground or below ground distribution substations Communications buildings
Metering	AMI network communications AMI single phase direct connected meters AMI three phase direct connected meters AMI LV CT connected three phase meters. Low voltage metering current transformers Pole top high voltage metering VT & CT transformers (CP/PAL owned) Boundary metering HV & EHV Zone substation metering transformers (CP/PAL owned) Legacy type 5 MRIM Meters Legacy type 6 (basic) Meters Timber meter boards (includes CP/PAL owned fuse or facia mounted service protective device (SPD) holders and neutral links)
Distribution switchgear	Circuit breakers Automatic circuit re-closers (ACRs) Switches Ring main units (RMUs)
Service lines	Overhead low voltage service assets Service cable attachment fittings Service protection devices Junction boxes