AusNet

Distribution Annual Planning Report

2025-2029

30 December 2024

AusNet

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1. Overview

AusNet Electricity Services Pty Ltd (AusNet) is a regulated Victorian Distribution Network Service Provider (DNSP) covering eastern rural Victoria and the fringe of the northern and eastern Melbourne metropolitan area.

This Distribution Annual Planning Report (DAPR) has been prepared in accordance with clause 5.13.2(a)(2) of the National Electricity Rules (NER) and provides the information specified in the NER Schedule 5.8. This report also complies with clause 19.4 and Schedule 2 of the Victorian Electricity Distribution Code of Practice (ED CoP).

The DAPR provides information (among other things) on existing and forecast system limitations on our distribution network, and where and when they are expected to arise within the forward planning period from 2023/24 to 2027/28. The DAPR also denotes whether system limitations are subject to the Australian Energy Regulator's (AER) Regulatory Investment Test for Distribution (RIT-D). The DAPR complies with the requirements of clause 5.13.2 the National Electricity Rules (NER). This report is published annually

The DAPR includes a description of our network, asset management approach, planning and forecasting methods and forecasts, and a summary of demand management activities. It also provides information on the capacity of the network and system limitations for sub-transmission lines, zone substations and 22 kV feeders, along with the options being considered to address those limitations. Information on our planned asset replacement, retirement and de-rating works, along with our metering and information technology systems expenditure plans and our network performance and targets in the areas of power quality and reliability is also provided.

Information regarding planning for transmission to distribution connection points, required by clause 5.13 of the NER, is covered in the Transmission Connection Planning Report (TCPR)[1].

Maps of AusNet network coupled with corresponding data are provided on our corporate website, in accordance with the requirements of schedule 5.8 (n) of NER: AusNet - Rosetta Data Portal (ausnetservices.com.au)

These maps are updated annually and/or following major project completions to provide the latest available information on current and emerging feeder, zone substation and sub-transmission network limitations.

Any information provided using the system limitation template must be read in conjunction with this DAPR.

[1] A copy of the 2023 Transmission Connection Planning Report and Terminal Station Demand Forecasts can be viewed at AusNet website: TRANSMISSION CONNECTION PLANNING REPORT (ausnetservices.com.au)

2. Introduction

This Distribution Annual Planning Report (DAPR) 2025-2029 is prepared by AusNet regarding its electricity distribution network and in accordance with the requirements of clause 5.13.2 of the National Electricity Rules (NER)[2] and clause 19.4 and Schedule 2 of the Victorian Electricity Distribution Code of Practice (EDCoP).

2.1. Purpose

The purpose of this report is to describe AusNet distribution network, explain the approach to network planning, provide forecasts for the forward planning period, describe constraints on the network and detail plans to address these constraints.

[2] A copy of the National Electricity Rules can be found at the Australian Energy Market Commission's website: http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html

3. AusNet's electricity distribution network

This section presents an overview of AusNet electricity distribution network, in accordance with the requirements of schedule 5.8 (a) of the NER.

3.1. Network location

AusNet operates and manages an electricity distribution network serving the fringe of the northern and eastern Melbourne metropolitan area and the eastern half of rural Victoria (see Figure 1) delivering electricity to approximately 809,000 consumers.

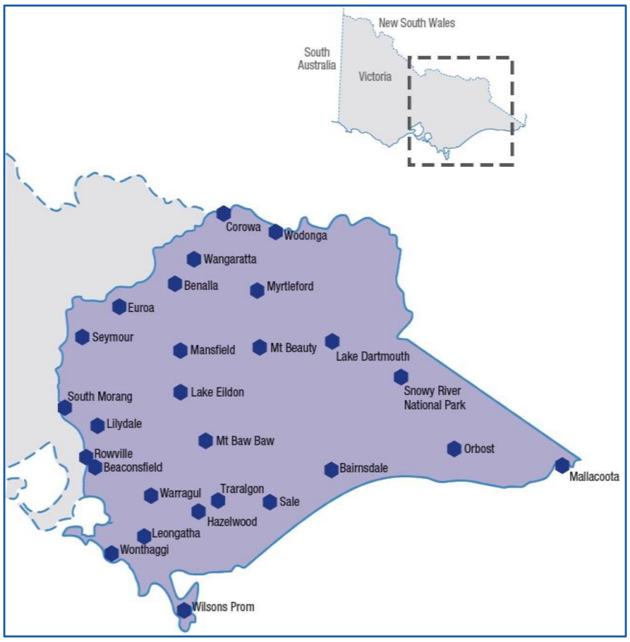

Figure 1: AusNet Electricity Distribution Network

AusNet distribution network is split into three regions, Central, East and North, as shown in Figure 2 below.

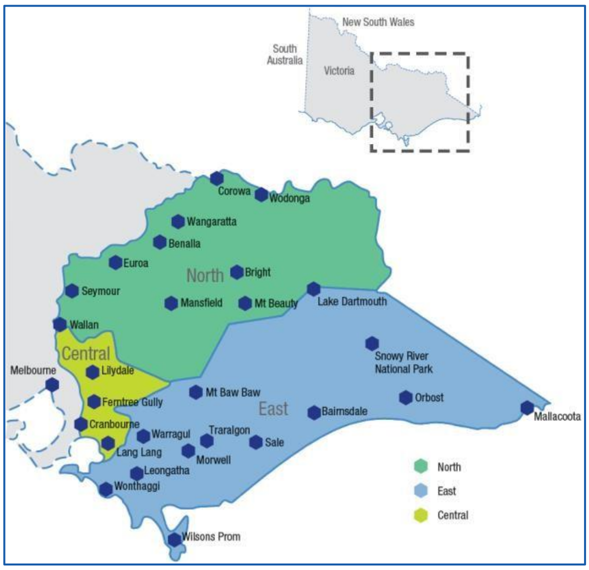

Figure 2: AusNet Service Delivery Regions

The distribution network is in a climate which is classified as temperate. The network area does not span across different classifications of climate.

The distribution network is located in areas where the average annual rainfall ranges from 600 mm to 1,200 mm. Some parts of the network in the Northern and Eastern regions are affected by flooding hazards. Approximately 35% of all network feeders have some parts in flood hazardous areas.

Approximately two-thirds of the distribution network is in areas designated as Bushfire Prone.

There are 362 distribution feeders, of which 14% are classified as Long Rural, 40% are classified as Short Rural and 46% are classified as Urban. A large proportion of feeders supply low density (lot sizes > 2000 m^2) customer areas. Twentynine percent of distribution feeders have less than ten customers per kilometre of line length. Customers supplied in these areas amount to 16% of the total customers served by AusNet.

The electricity network comprises a 'sub-transmission' network that consists of predominantly overhead lines that operate at 66 kV, and a 'distribution' network, which generally operates at a voltage of 22 kV and consists mainly of overhead lines but also includes underground cables. Some customers in remote and low population density rural areas are supplied by Single Wire Earth Return (SWER) 12.7 kV distribution networks. Most customers are supplied at 230 V single phase or 400 V 3-phase by Low Voltage reticulation via distribution transformers.

3.2. High Voltage Sub-Transmission Network

The sub-transmission network is supplied at eleven connection points from the Extra High Voltage (500 kV, 330 kV, 275 kV and 220 kV) transmission network that is owned and operated by AusNet Transmission Group Pty Ltd.

The sub-transmission network consists of overhead electricity lines operating at 66 kV, which are generally formed in loops fed from individual terminal stations. Although more interconnections have recently been established, these sub-transmission loops are generally not interconnected except under abnormal or emergency conditions. The loop configuration serves to maximise the reliability of the sub-transmission network by providing most zone substations with at least two sources of supply.

The length of each 66 kV sub-transmission loop depends on the proximity of the load centres to the terminal stations. The sub-transmission network has been developed over many years and therefore incorporates differing technologies, design standards, and plant and equipment types. As a result of these variations in the network, it has differing supply capacities. The capacity of each network loop is determined by numerous factors, including:

- Design working temperature
- Design of the particular network (which may impose loading or operational constraints)
- Thermal loading under outage conditions
- Voltage stability under outage conditions
- Conductor size and type
- Plant and equipment ratings.

Zone substations are generally supplied from more than one incoming 66 kV line, which are connected to the buses via circuit breakers. Within the zone substation, the incoming supply is transformed via one or several 66/22 kV transformers, ranging in size from 5 MVA to 33 MVA, and typically connected in parallel, unless separated to manage fault current levels to within regulatory and asset limits, or to manage rapid earth fault current limiter (REFCL) sensitivity required to meet REFCL compliance on total fire ban (TFB) days.

The 22 kV windings of the transformers are usually 'star' connected and earthed directly or via a Neutral Earthing Resistor (NER) or a REFCL to limit the phase-ground fault current. Most zone substation power transformers are equipped with on-load tap changing (OLTC) facilities to provide automatic control of the operating voltage. Additional reactive power support is provided by capacitor banks installed at most zone substations.

3.3. Protection

Protection of the sub-transmission system is achieved by a combination of current and voltage transformers, circuit breakers and protection devices arranged in schemes, which monitor the voltages and currents for abnormal conditions and initiate disconnection of supply in accordance with pre-established protocols. Protection schemes include:

- Distance
- Differential
- Over Current
- Earth Fault
- Residual Over Voltage/Neutral Displacement.
- Under / Over Voltage and Under Frequency to initiate Load Shedding.

The protection applied to the sub-transmission network is duplicated and coordinated with that at the terminal stations, other zone substations and associated distribution network feeders. As per the existing industry practice, bare conductor overhead lines are fitted with automatic reclose facilities to minimise the impact of transient faults.

3.3.1. Earthing

Plant and equipment within the sub-transmission network employ local earthing whereby each piece of electrical equipment and conductive structure is directly connected to the general mass of earth via a dedicated earth connection. The 66 kV networks are referenced to earth via the connection transformers within the transmission network, which have their 66 kV winding star-points connected directly to the earthing grids of the respective terminal stations.

The sub-transmission network is an 'effectively' earthed system. In the event of a fault to earth on this network the earthing assets enable the flow of electricity to the general mass of earth, under such circumstances that step, touch and transfer voltages are managed, fire ignition is minimised, and electrical protection systems operate to limit network damage.

3.4. Medium Voltage Distribution Network

The 22 kV distribution network is currently supplied by fifty-eight zone substations, which are located near to the load centres. Additionally, three terminal stations supply 22 kV distribution feeders. Three 22/6.6 kV step-down substations supply the Mount Dandenong area via three 6.6 kV feeders. The Latrobe Valley power stations and mines are in part supplied via dedicated substations.

The Medium Voltage (MV) distribution network consists of 362 feeders as of 31 October 2024. These feeders predominantly operate at 22 kV, with three 6.6 kV feeders supplying the Mt. Dandenong area and a further seven 6.6 kV and two 11 kV feeders supplying the coal fired power stations, associated mines, and support workshops within the Latrobe Valley. A total of approximately 468 customers are partly served by feeders from adjacent DNSPs, three United Energy feeders (DN4, NW13, RWT13) and two Essential Energy (EE) feeders (TRC01 and BOM8M3[3]).

Distribution feeders are generally operated in radial mode. In urban areas they can often be operated in open-loop arrangement via switches installed to provide alternative points of supply and thus improve the reliability of the network.

In rural areas, the average feeder length is 153 km (including spurs) with few alternative points of supply. This is the average of the combined MV overhead and underground line lengths from feeders classified as short and long rural in FY24 AER RIN. Distribution feeders are usually three-phase, but some spur lines, especially in rural areas, are single-phase supplied from two of the three available phases.

Remote and low population density rural areas are often supplied by Single Wire Earth Return (SWER) MV distribution networks. AusNet has over 540 SWER networks as of 31 October 2024. The SWER networks are supplied from two phases of the three-phase network via an isolating transformer, which provides the appropriate voltage transformation, regulation, and electrical isolation between the two networks. The SWER networks operate at 12.7 kV, with most overhead lines constructed using 3/2.75 mm steel conductor.

3.4.1. Distribution Substations

Distribution substations are located throughout the MV distribution network and provide transformation from the 22 kV reticulation to the customer's nominal service voltage (230/400 V or 230/460 V).

They range in capacity from 10 kVA to 2000 kVA and are classified into the following major types:

[3] AusNet identifies EE's BOM8M3 feeder as BM8B31, BM8B32 and BM8B33 feeders.

- Pole Mounted
- Ground Mounted Kiosk
- Indoor.

Distribution transformers on the three-phase network have a delta-star winding arrangement with a common voltage rating of 22 kV/433-250 V, while those on a single-phase network generally have a centre point earthed secondary winding and the voltage rating of 22 kV/250 V/500 V is common. Distribution transformers installed on the SWER circuits commonly have voltage ratings of 12.7 kV/250 V/500 V. The off-load voltage taps on each transformer can deliver the nominal voltage standard of 230 V/400 V and 230 V/460 V within +10%/-6% at the customers' point of connection.

3.4.2. Protection

Protection equipment, including protective relaying schemes, in conjunction with circuit breakers, automatic circuit reclosers, sectionalisers and fuses are applied to the distribution system to:

- Ensure safety of the general public and electricity workers by minimising any hazardous step, touch or transfer potential by isolating the faulted section of the plant within the protected zone.
- Ensure service continuity by sectionalising faulted elements of the network from unaffected portions of the network and therefore minimise disruption to most customers.
- Minimise equipment damage.

3.4.3. Earthing

Within zone substations the star-point of the 22 kV windings is connected to the station earth grid, directly or via a neutral earthing resistor, and thus to the general mass of earth.

Metallic MV equipment frames, switch handles, cable screens, conductive structures (e.g. concrete poles), surge diverters, exposed metal parts containing or supporting the MV conductors, and all interconnected metallic parts, are directly connected to a local MV earth and thus to the general mass of earth. These earthing systems are designed to:

- Ensure correct functioning of the protection systems.
- Limit over-voltages during fault conditions.
- Manage step, touch and transfer potential in high risk and well frequented areas.
- Co-ordinate transfer voltages with other authorities' assets in the vicinity.

3.4.4. Rapid Earth Fault Current Limiter (REFCL)

As of 1 November 2024, AusNet has installed Rapid Earth Fault Current Limiter (REFCL) technology at twenty-two of the twenty-two zone substations mandated by the Victorian Government in 2016.

The electrical protection technology is designed to minimise the fault current (energy) dissipated from phase to earth (wire to ground) faults on the 22 kV network to reduce the risk of fire ignition associated with network incidents.

Implementation and testing by government of two different types of REFCL technology was completed at Kilmore South zone substation on a limited 40 km section of network in 2014. Based on a sample period of network fault data, analysis undertaken by the Government and CSIRO predicts network fire related incidents associated with the nominated zone substations can be reduced by between 50-55%.

There are two types of REFCL technology available:

- The Ground Fault Neutraliser (GFN) which reduces single phase to earth fault currents on a network. The GFN does this by using resonant earthing with an enhanced 'residual current compensation feature' that injects current into an arc suppression coil (ASC) at 180° out of phase with the residual fault current. The GFN instantaneously eliminates the large fault current, reducing it to under 25 A and then close to 0 A within 3 cycles or 60ms. Its operation causes the phase voltage of the faulted phase to be reduced to near earth potential (zero volts), whilst the healthy phases rise by 173%, nominally from 12.7 kV to 22 kV. The implication of higher voltages on the healthy phases means that implementation of the REFCL technology can require significant asset replacement investment to ensure that all assets are rated for the higher phase voltages that they would be exposed to under fault conditions.

- The Advanced Residual Current Compensation (ARCC) which uses resonant earthing to reduce single phase to earth fault currents on a network

As the GFN has been available for implementation since the start of the REFCL implantation program, there are more GFNs deployed on AusNet distribution networks than ARCC's. ARCC have been implemented at Kinglake, Sale, Lang Lang, Kalkallo and Benalla.

REFCLs can be deployed in the zone substation or on individual 22kV feeders as a 'remote REFCL substation'.

3.4.5. Overhead Lines

There are approximately 332,500 poles supporting distribution and sub-transmission networks.

Most overhead lines utilise aluminium conductors, although copper was previously used and remains in service in some (generally older) areas. Steel conductors are predominantly utilised in rural (including SWER circuits) distribution areas.

The most common conductors used in the MV overhead network are Steel Conductor (SC) – 3/2.75, Aluminium conductor steel-reinforced (ACSR) – 3/4/2.5, 6/1/2.5, 6/1/3.0, 6/1/3.75, 6/1/4.75 and 6/4.75/ 7/1.60 and All Aluminium Conductor (AAC) – 7/2.5, 7/3.0, 19/3.25,19/3.75, 37/3.75, 7/4.75 and 19/4.75.

High Voltage Aerial Bundled Cable (HV ABC) is utilised for some 22 kV lines in environmentally sensitive treed areas, such as the Dandenong Ranges, to mitigate fire risk and minimise the incidence of tree and bark related faults. The main sizes of HV ABC used on the networks are 35 mm^2 and 185 mm^2 with aluminium conductors and non-metallic screens. A new type of HV ABC has been introduced to improve reliability. The new type is the Light Duty Metallic Screened HDME sheathed HVABC. This is generally known as LD MS HVABC and the standard conductor sizes are 35 mm^2 Al & 185 mm^2 Al. These cables can be used as the standard form of construction for both new overhead HV and for replacement of bare overhead HV in AusNet HV distribution network.

AusNet has also trialled and introduced:

- The Spacer Cable System as a standard MV cable system permitted for use on AusNet distribution network. The 22 kV Spacer Cable System consists of three covered conductors which are separated using a 'Spacer' and the whole system is supported by a tensioned catenary (messenger) wire. Spacers are generally placed every 10-12 metres along the span hung on the messenger wire. This system is suitable for heavy tree areas including where tree overhang is present (56Ms). The standard conductor sizes are 35 mm2 Al, 50 mm2 Al & 150 mm2 Al.

- The Amokabel Open Wire Covered Conductor (OWCC) on standard MV cable system permitted for use on AusNet distribution network. The OWCC connection arrangement is like existing bare conductor and pole installation, however with different cross-arm mounts. The system is suitable for heavy tree areas including REFCL Network. The standard conductor sizes are 19/3.26mm (CCSX 159 AAAC), 1+6/3.37mm (CCSX 62 ACSR), and 7/2.12mm (CCSX 25 ACS SWER).

AusNet for the first time introduced a Hybrid Underground system during 2015. The hybrid system is a system which contains underground HV cables and where the existing substations, protection devices and low voltage network is left pole mounted and overhead. The hybrid system is an alternative supply arrangement in areas where the overhead medium voltage (22 kV, 11 kV or 6.6 kV) network is replaced with underground cable and where there is no space available to install kiosk substations. The standard conductor sizes are 35 mm^2 Al, 185 mm^2 Al, 240 mm^2 Al & 300 mm^2 Al and the cable types are standard underground cables.

3.4.6. Underground Lines

Approximately 2,625 km (route length) of medium voltage underground cables are utilised for distribution in new urban residential developments and where other circumstances may apply such as visual impact, vegetation management, etc. The cables have cross-linked polyethylene (XLPE) insulation, aluminium conductors and 3-core construction. The main sizes are 35 mm^2, 185 mm^2, 240 mm^2 and 300 mm^2. There are also significant quantities of HSL

(Hochstadter type cable - Paper insulation, screen type and lead sheath on each core, steel wire armour) underground cables utilised in the underground distribution network.

3.4.7. Electric Line Construction (Codified) Areas

Amendments to the Electricity Safety (Bushfire Mitigation) Regulations 2013 introduced 1 May 2016 require any planned conductor replacement (1 kV to 22 kV) of four or more consecutive spans or any new medium voltage electric line to be constructed with insulated or covered conductor within codified areas.

The locations of medium voltage lines specified within the regulations are defined as those lines being within an "electric line construction area" (codified area). The codified areas within AusNet franchise area are illustrated in

Figure 3 (red shaded areas). Further information may be found in AusNet "Bushfire Mitigation Plan – Electricity Distribution Network"

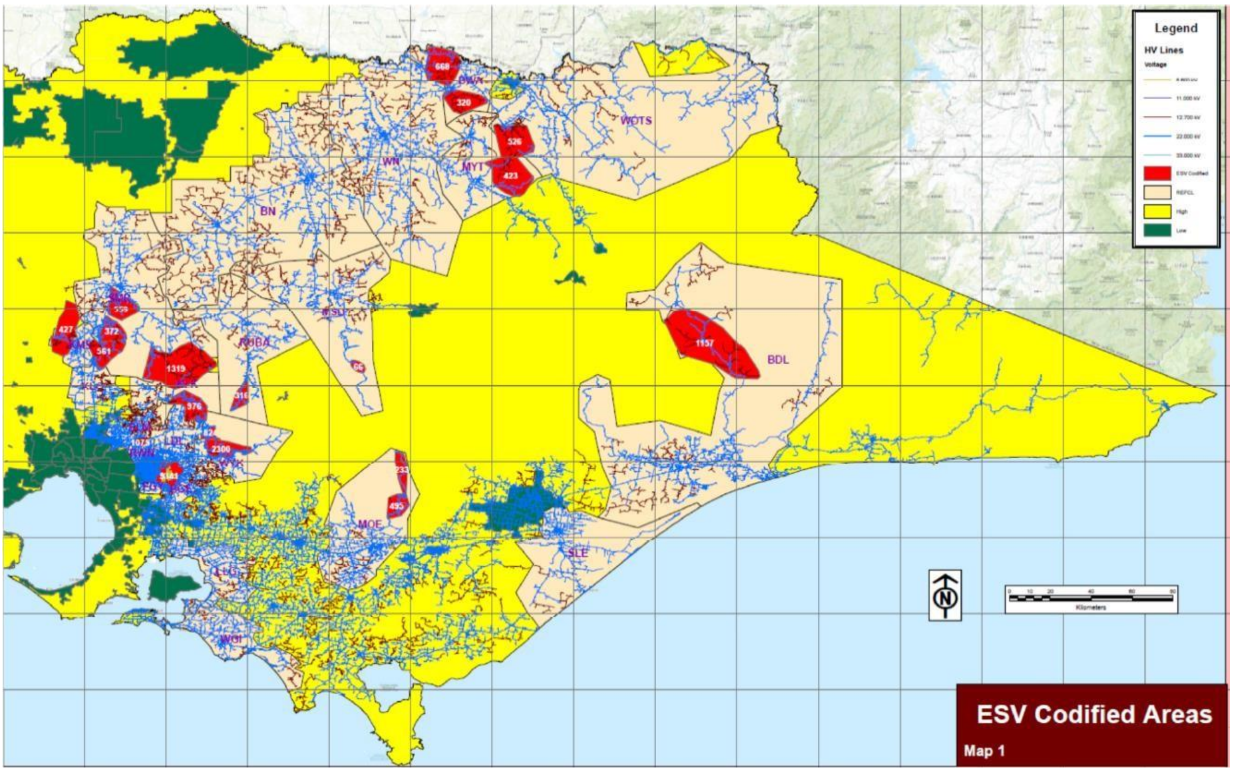

Figure 3: Codified Areas within AusNet Distribution Network

3.5. Low Voltage Distribution Network

In urban and some rural locations reticulation at Low Voltage (LV) is utilised to supply small groups of customers. The LV lines are typically either three-phase (400 V) or two-phase (460 V) [with +10%/-6% voltage band] circuits with a neutral conductor. Insulated customer service cables are connected to these LV lines.

There is generally no permanent connection between adjacent LV circuits in urban areas although switching devices enable interconnections between some areas and load transfers in emergency conditions.

The LV overhead reticulation network consists of both open (bare) wire and insulated wire, Low Voltage Aerial Bundled Cable (LV ABC), construction.

Bare Conductor – Most of the LV bare conductors are of aluminium construction; although, some copper is in service in older areas. Typically, the standard conductor utilised for LV reticulation is 19/3.25 mm all aluminium conductor (AAC); although, there are other types and sizes of conductors still in service that were utilised on the LV network in the past.

LV ABC – LV ABC is cross linked polyethylene (XLPE) insulation over each of four aluminium cores. Typical conductor sizes are 95 mm2 and 150 mm2.

LV Cable – LV underground cables are sized to suit the application but are generally 185 mm2 and 240 mm2 with aluminium conductors and XLPE insulation.

3.5.1. Protection

The LV network protection is provided by fuses or in some cases moulded case circuit breakers installed on the LV side of the distribution transformers. The fuses are rated, and the circuit breaker tripping is set to suit the application, substation loading and coordination with MV fuses. Other considerations such as LV circuit lengths and fault current limits are also considered.

3.5.2. Earthing

The following types of earthing are applied within the LV distribution network:

- Individual Multiple Earthed Neutral (IMEN) – An earthing arrangement where the LV neutral conductor is permanently connected to earth at the substation supplying the system, all customers' premises and an auxiliary earth at the remote end of the LV reticulation Network.
- Interconnected Multiple Earthed Neutral – An earthing arrangement where the LV neutral conductor is permanently connected to earth at the multiple substations supplying the system, all customers' premises and at any point throughout the neutral system as required.
- Common Multiple Earthed Neutral (CMEN) – An earthing arrangement where all the MV and LV equipment is permanently connected to a common earth. The LV neutral conductor is connected to earth as per interconnected Multiple Earthed Networks and is used to bond other MV earthing points within the Network.
- Direct Earth – An earthing system where the customer's neutral conductor is directly connected to the Distribution Substation earth via underground cable sheath or dedicated overhead earth conductor.

3.5.3. Services

Connection from the customer point of supply to the LV distribution network is achieved via service cables. Service cables may be placed either overhead or underground. The aerial service cables are typically XLPE insulated[2] core or 4 core construction with aluminium conductors of 25 mm^2 and 35 mm^2 and, as required, 95 mm^2 and 150 mm^2 aerial bundled cables. The underground service cables are tapped from the underground LV reticulation cables using tee joints. Standard service cables are 16 mm^2, 35 mm^2 and 50 mm^2 with copper conductors and XLPE insulation.

3.6. Communications Network

The communication network provides services for the following applications:

- Power system protection signalling.
- System Control and Data Acquisition (SCADA) for zone substations, Automatic Circuit Reclosers, and Sectionalisers.
- Operational Voice communications.
- Power Quality monitoring.
- Asset condition monitoring.
- Smart metering (Advanced Metering Infrastructure, AMI).

These services are provided by either the private AusNet communication network or third-party services. Third party services can be used for all applications except power system protection signalling because of the stringent technical requirements. Where there is no requirement for power system protection, the choice between the private AusNet network and third-party service is determined on lowest economic cost.

40 zone substations are connected to the optical fibre network. Eleven zone substations and about 2,300 pole top devices are connected by 4G/5G/satellite and 159 by private AusNet point-to-multipoint radio.

3.6.1. Communication Asset Types

Communication assets include telephone exchanges, network technologies, wireless access systems, and bearers. Network technologies include DIC systems (ethernet switches, routers, serial servers), Plesiochronous Digital Hierarchy (PDH), Synchronous Digital Hierarchy (SDH), and Wave Division Multiplexers (WDM), and Multiprotocol Label Switching (MPLS). Wireless access systems include the private point to multipoint radio and remote modems connecting field devices to third party mobile systems. Bearers cover point-to-point microwave radios and optical fibre cables. There are two types of optical fibre assets installed on distribution poles to support the communications network, All Dielectric Self Supporting (ADSS) and Optical Ground Wire (OPGW).

3.7. Distribution Asset Summary

Table 1 lists common asset types, sub-types, and quantities.

Table 1: Number and types of assets

#	Asset Type	Description	Number
1	Connection Points	Terminal Stations (66kV Connection Point)	11
2	Connection Points	Terminal Stations (22kV Connection Point)	2
3	Connection Points	Terminal Stations (11kV Connection Point)	1
4	Connection Points	Zone Substations (66/22kV)	58
5	Connection Points	Substations (22/6.6kV)	3
6	Connection Points	Zone Substations (Single Customer)	9
7	Connection Points	Switching Station	1
8	Transformers	Zone Substations Transformers[4]	144
9	Transformers	Distribution Transformers (Pole Mounted)[6]	57,725
10	Transformers	Distribution Transformers (Kiosk, Ground Outdoor or Indoor Chamber Mounted)[6]	5,644
11	Circuit Breakers	High Voltage (>22kV)[6]	188
12	Circuit Breakers	Medium Voltage (≤22kV)[6]	2,585
13	Feeders	Number of 22kV feeders	364
14	Feeders	Number of 11kV feeders	1
15	Feeders	Number of 6.6kV feeders	8
16	Conductors	Overhead (Low Voltage <1kV) (km)[6]	6,565
17	Conductors	Overhead (SWER) (km)[6]	6,421
18	Conductors	Overhead (Medium Voltage 11 and 22kV) (km)[6]	22,537
19	Conductors	Overhead (High Voltage 66kV) (km)[6]	2,478
20	Conductors	Underground (Low Voltage <1kV) (km)[6]	5,838
21	Conductors	Underground (Medium Voltage 11 and 22kV) (km)[6]	2,764
22	Conductors	Underground (High Voltage 66kV) (km)[6]	16
23	Conductors	Service Lines (number of services)[6]	197952
24	Poles	Wood Poles[6]	179,952
25	Poles	Concrete Poles[6]	133,011
26	Poles	Steel Poles (excluding public lighting poles)[6]	411
27	Poles	Public Lighting Poles[6]	111,448
28	Poles	Crossarms[6]	405,400

[4] AusNet Regulatory Information Notice – Category Analysis 2023

29	Communications	Optical fibre Cable (OPGW, ADSS, Underground) Routes	678
30	Communications	Radio systems (Point to point and Point to Multipoint)	86
31	Communications	Network Technologies (DIC [Routers, Switches and Serial servers], PDH, SDH, WDM and TPS)	323
32	Communications	Telephone exchanges	7
33	Communications	Point to point radio links – AMI	0
34	Communications	Access Points - AMI	689
35	Communications	Relays - AMI	838
36	Communications	Microaps - AMI	4600

3.8. Methodologies used in preparing the DAPR

The DAPR covers a five-year forward planning period. The annual planning process commences after the extended summer season ending 31 March each year. The demand forecasts for connections points, zone substations, sub-transmission lines and distribution feeders are developed using the method described in Section 4.1, and network limitations are identified using the Probabilistic Planning Philosophy.

3.8.1. Planning Process

The planning activities are discussed in this section of the report and consist of the following steps:

- Review the long-term strategy for the distribution system with due consideration of network reliability, network resilience, network capacity, quality of supply, network safety, environmental requirements, and asset management and regulatory strategies.
- Forecast the maximum and minimum load demand for the next ten-year period.
- Forecast the network capacitive current for the next ten-year period.
- Confirm the capability of the existing network.
- Identify network constraints or network performance issues.
- Formulate options to resolve network constraints or needs.
- Seek non-network options including demand-side options. Publish a non-network options report under RIT-D requirements where appropriate.
- Study these options to ensure compliance with technical limits, planning philosophies, regulatory criteria and guidelines, reliability and quality of supply standards and asset management strategies.
- Develop cost estimates for each option as well as cost savings and benefits of each option and establish the most cost-effective alternative that meets the technical and other requirements.
- Investigate the economic viability of the most cost-effective option by comparing the economic cost of the probability weighted energy at risk due to the contingency, reliability, or performance gap with the cost of reducing this risk or improving the network performance.
- Prepare a planning report documenting all considerations and recommendations.
- Prioritise the different distribution projects based on the company's business strategy and funding guidelines.
- Obtain approval of the recommended plans, document plans and initiate execution of the projects in the plan.
- Publish draft and final project assessment reports under RIT-D requirements as appropriate.

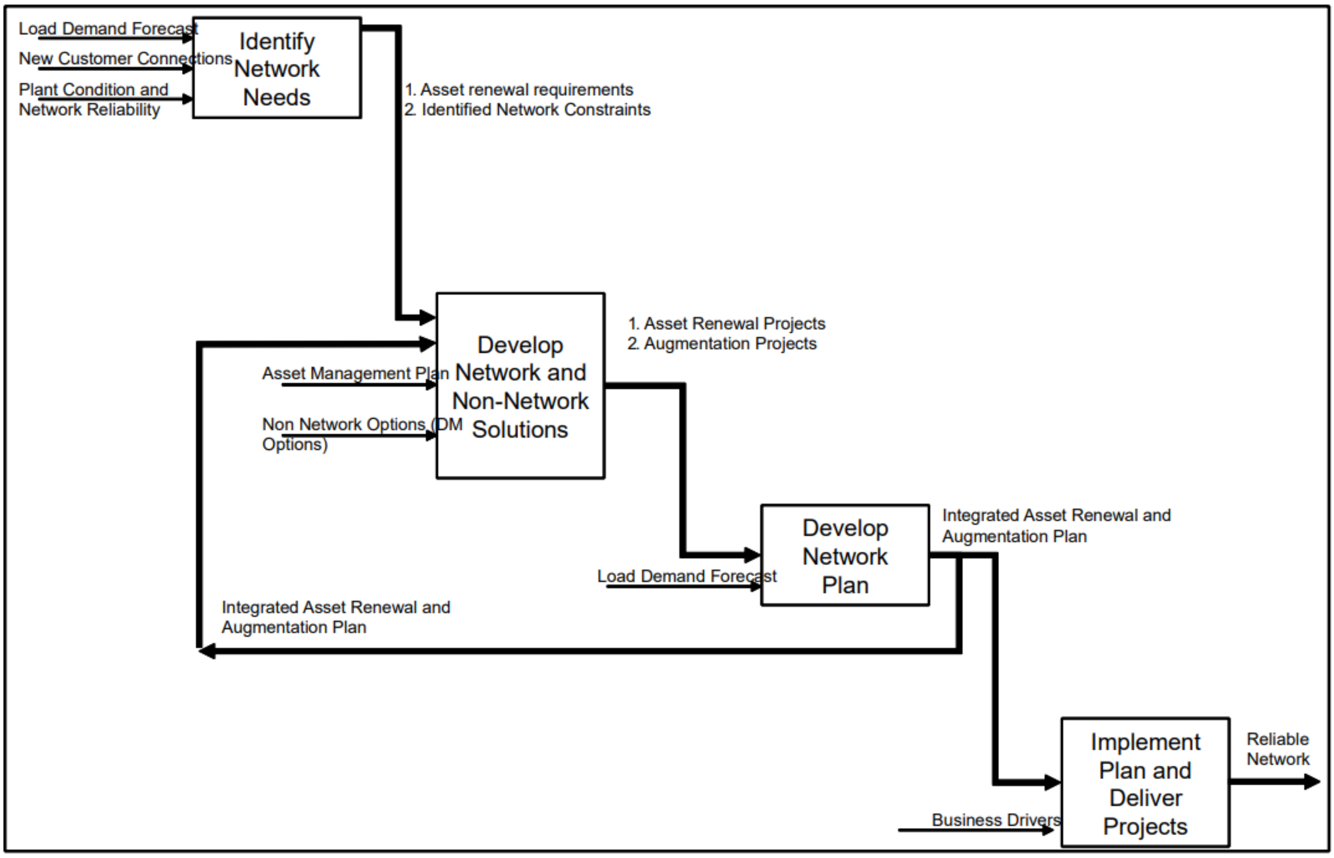

Figure 4: Distribution Network Planning Process

3.8.2. Identification of network needs or constraints

Network augmentation is essentially required to provide additional power transfer capacity to meet increasing customer load or generation levels or, in the case of rapid earth fault current limiter (REFCL) protected zone substation, additional capacity to meet network capacitive current growth. Asset retirement and, where economically justified, replacement is required when the deteriorated condition of existing assets poses a service level risk, driven by reliability, safety, network security, environmental and plant damage risks, that outweighs the cost of retirement and/or replacement. The need for network augmentations or asset retirement and replacement is generally driven by the following factors:

- Increased load demand at existing supply points.
- New loads connecting to the distribution network.
- New network, resulting in capacitive current growth, to supply new connections.
- New generation connections or increased generation at existing connection points.
- Meeting quality of supply requirements.
- Improving the reliability of the network in response to the regulatory incentive scheme.
- High network losses supporting the justification for network augmentation based on reduced energy and demand losses as well as environmental benefits.
- Environmental requirements.
- Deteriorating condition of ageing assets.
- Risk mitigation.

Increased penetration of Customer Energy Resources (CER) have resulted in significant reverse power flow and light load conditions in some parts of the network and triggered augmentation of the low voltage network to manage these reverse flows and voltage levels. In response to the reduction in minimum demand and changes in the load shape driven by increased penetration of CER, AusNet has developed a 'minimum demand' forecast for this DAPR to better communicate this new phenomenon.

3.8.3. Overall objective of network planning

The planning standards and criteria applied in network development are a significant determinant of network related costs. Costs associated with distribution connection facilities can be considered to comprise of two parts:

- The direct cost of the service (as reflected in network use of system charges and the costs of losses).
- Indirect costs borne by customers as a consequence of supply interruptions caused by network faults.

In developing and applying their planning standards and investment criteria, AusNet aims to develop network facilities in an efficient manner that minimises the total (direct plus indirect) life-cycle cost of network service borne by customers.

This basic concept is illustrated in Figure 5 below.

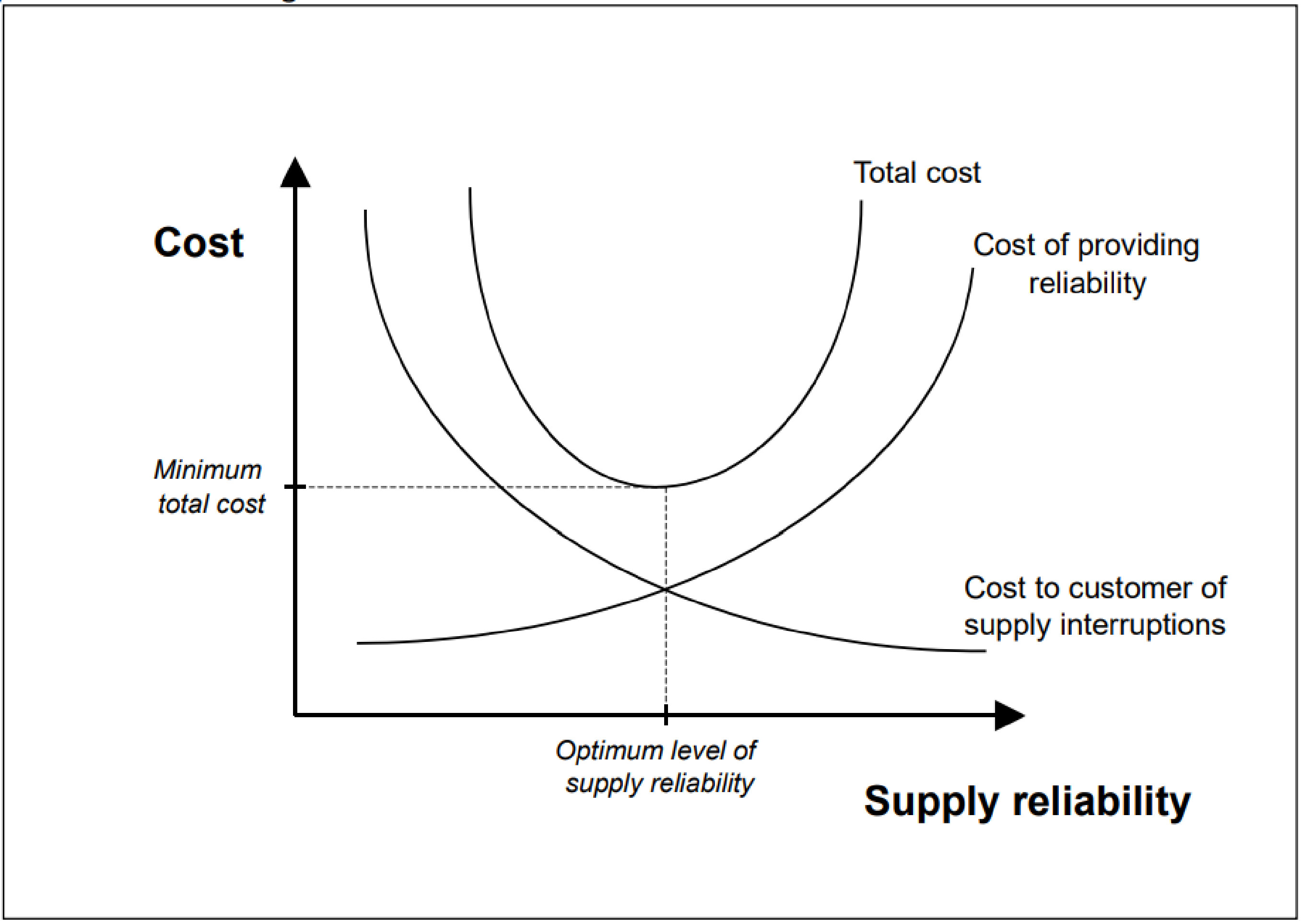

Figure 5: Balancing the direct cost of service and the indirect cost of service level risks including supply interruption

Additionally, AusNet distribution connection investment decisions aim to maximise the net present value to customers, having regard to the costs and benefits of non-network alternatives to augmentation. Such alternatives include, but are not limited to, demand-side management and embedded generation.

3.8.4. Overall approach to distribution planning and investment evaluation

AusNet uses a probabilistic approach to network planning. Under probabilistic planning, the deterministic N-1 criterion applied in some networks is relaxed and simulation studies are undertaken to assess the amount of energy that would not be supplied (or curtailed) if an element, or elements, of the network were out of service. The application of this approach often leads to the deferral of augmentation that would otherwise proceed under a deterministic standard. Under a probabilistic network planning approach, conditions often exist where some of the load cannot be supplied (or some of the generation requires curtailment) with a network element out of service (hence the N-1 criterion is not met); however, the value of the energy not supplied is insufficient to justify additional investment, considering the probability of a forced outage of a particular network element.

The transmission connection assets for which the DNSPs have planning responsibility form part of the Victorian electricity transmission network. Given that the Australian Energy Market Operator (AEMO) applies a probabilistic network planning approach to the development of the shared transmission network, the Victorian DNSPs consider it appropriate to adopt a similar approach in distribution network planning and investment decision analysis. AusNet considers it is appropriate to plan the distribution network (i.e. zone substations and sub-transmission lines) in a manner consistent with the planning for the 'upstream' network and connection points. Implicit in the use of a probabilistic approach is acceptance of the risk that there may be circumstances (such as the loss of a transformer during a high demand period) when the available zone substation or 66 kV loop capacity will be insufficient to meet actual demand and significant load shedding could be required.

3.8.5. Valuing supply reliability

To determine the economically optimal level and configuration of network capacity to service maximum demand, 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. This is referred to as the value of customer reliability (VCR).

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 consumers resulting from electricity supply interruptions) that provides a guide to the likely value.

In July 2018, a final Rule determination on the VCR came into effect giving the AER responsibility for developing and publishing a VCR methodology and VCR estimates. In December 2019, the AER published its VCR methodology and VCR estimates[5].

The VCR represents, in dollar terms, the estimated aggregated value that customers place on the reliable supply of electricity. This value varies by customer type and outage characteristics, and therefore varies at different locations within in the network based on the mix of customer types at that point. As customers cannot directly specify the value they place on reliability, the VCR plays an important role in determining the efficient level of investment in electricity services required by customers.

A VCR of $41.01/kWh has been used when calculating the cost of expected unserved energy (EUSE) in limitation assessments included in this DAPR. This VCR was calculated from the values published by AER[8] on 18 December 2022 and AusNet's customer composition of approximately 44.4% residential, 5.1% agricultural, 35.3% commercial, and 15.2% industrial.

3.8.6. Valuing curtailed generation

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 change[6]. 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.

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[5] AER, Final Report on VCR values – annual update, December 2021, available at https://www.aer.gov.au/networkshttps://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/updatepipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/update [8] Values of customer reliability | Australian Energy Regulator (AER)

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

In June 2022, the AER published its Customer Export Curtailment Value Methodology. At the same time, the AER also published a DER Integration Expenditure Guidance Note[7], 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 iii) quantify DER benefits in a cost-benefit analysis.

3.8.7. Application of the probabilistic approach to network planning

The probabilistic planning approach involves estimating the probability of various network conditions coinciding, such as plant outages coinciding with peak import or export conditions, and weighting the service level costs of such events by their probability of occurrence to assess:

- The energy at risk of load not being supplied (or generation being curtailed) if no risk mitigation action is undertaken; and
- Whether it is economic to invest in risk mitigation action to reduce the forecast service level risk.

The quantity and value of energy at risk is a critical parameter in assessing a prospective risk mitigation investment. Probabilistic planning aims to ensure that an economic balance is struck between the cost of:

- Providing supply redundancy and increased levels of safety to manage service level risk; and
- Exposure to the conditions (plant outages or network loading levels) that result in the identified supply level risk being realised.

In other words, recognising that plant outages and very extreme loading conditions (either import or export) may occur for a small fraction of the year, it may be uneconomic to retire and replace poor condition plant or provide additional capacity to cover the possibility of a network outage under extreme conditions. Rather, the probabilistic approach indicates that service level risk mitigation action should take place only when the service level risk has increased to the extent that the value of expected unserved energy and risk exceeds the investment cost to reduce the level of expected unserved energy and risk.

This approach provides a sound estimate of the expected net present value to consumers of distribution system augmentation, retirement or replacement. However, implicit in its use is acceptance of the risk that there may be circumstances when the available distribution network will be insufficient to meet actual demand for distribution services. The extent to which investment should be committed to mitigate that risk is a balance between engineering and economic analysis; having regard for:

The results of probabilistic and deterministic studies of possible outcomes, and the inherent uncertainty of those outcomes.

Regulatory and other legal compliance obligations.

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 peak demand, and catastrophic plant failure leading to extended periods of plant unavailability.

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

The Victorian DNSPs' obligation (under clause 13.3 of the Victorian EDCoP) to use best endeavours to meet, among other things, reasonable customer expectations of reliability of supply.

3.8.8. Methodology for assessing supply risk at zone substations

The methodology for assessing supply risk at zone substations includes assessing the magnitude, probability and impact of loss of load (or curtailment of generation) at each zone substation.

The following key data are calculated for each zone substation:

- Hours at risk: For a given maximum (or minimum) demand forecast, this is the number of hours per annum that a zone substation operates beyond its firm import (or export) rating.

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

- Load at risk (or generation at risk): For a given maximum (or minimum) demand forecast, this is the maximum amount of load (or generation) that would be shed should an asset failure within the zone substation occur, due to an asset outage occurring coincident with operation of the zone substation beyond its N-1 import (or export) rating.
- Energy at risk: This is the amount of energy, weighted by the demand conditions considered (10% POE and 50% POE), that would not be able to be imported or exported from a zone substation, assuming an outage of a transformer, circuit breaker or other critical asset occurs at that station in that particular year. This measure provides an indication of the magnitude of energy that would not be supplied to the load during import (or the amount of generation curtailment needed during export) in the unlikely event of a major network asset outage.
- Expected unserved energy: This is the energy at risk weighted by the probability of potential network asset outages and their repair times. This measure provides an indication of the amount of energy, on average, that will not be imported (or exported) in a year, considering the low probability that a transformer, circuit breaker or other critical asset at the zone substation fails and is out of service.

Supply risk assessments for each zone substation provide estimates of energy at risk and expected unserved energy based on the demand forecasts.

3.8.9. Interpreting import and export limitations

Customer loads cause power to flow in the forward direction (i.e., towards the customer), and this is referred to in this DAPR as import. However, when sufficient numbers of embedded generating units are operating in aggregate, they may cause power to flow in the reverse direction (i.e., towards the transmission system) through various points within the upstream high-voltage distribution network. This is referred to in this DAPR as export.

An import limitation occurs when the maximum demand goes beyond the network asset's import rating (denoted as a positive number). Conversely, an export limitation occurs when the minimum demand is negative and goes beyond the network asset's export rating (denoted as a negative number).

The import ratings that are used for identifying network limitations under maximum demand conditions are mainly thermally limited, and generally higher in magnitude than the export ratings used for minimum demand conditions which are mainly voltage-limited. This is due to the limited capability of transformer buck-taps and On-Load Tap Changer (OLTC) mechanisms, and the magnitude of voltage rises occurring within the distribution network associated with reverse power flows.

The method adopted for assigning export ratings selects the smaller of the:

- Power flow limitation, being the same as the import rating (which may be determined by thermal capacity, protection or voltage drop considerations), except for some specific transformer OLTCs that can introduce up to a 70% reduction factor under reverse power flows;
- Voltage rise limitation being the largest reverse power flow that still maintains:
- Voltage rises within acceptable limits, while considering the voltage drops at maximum forward power flow, to maintain regulatory compliance for the steady-state voltage limits at customers' points of supply to the network; and
- Control of the voltage by way of remaining available transformer OLTC buck-taps;
- Downstream export ratings that may limit the magnitude of the reverse power flowing back into the upstream network.

3.8.10. Interpreting 'energy at risk'

When there is an import limitation, 'energy at risk' is an estimate of the annual energy that would not be supplied to the load if a zone substation network asset were out of service during critical import times, for a given maximum demand forecast and import rating.

Furthermore, when there is an export limitation, 'energy at risk' is an estimate of the annual energy that would need to be curtailed from generation sources if a zone substation network asset were out of service during critical export times, for a given minimum demand forecast and export rating.

Generally, the worst-case outage for zone substation risk is outage of a transformer, and this condition is referred to as its 'N-1' rating. The capability of the station with all transformers in service is referred to as its 'N' rating. The relationship between the N and N-1 ratings of a station and the energy at risk is depicted in Figure 6.

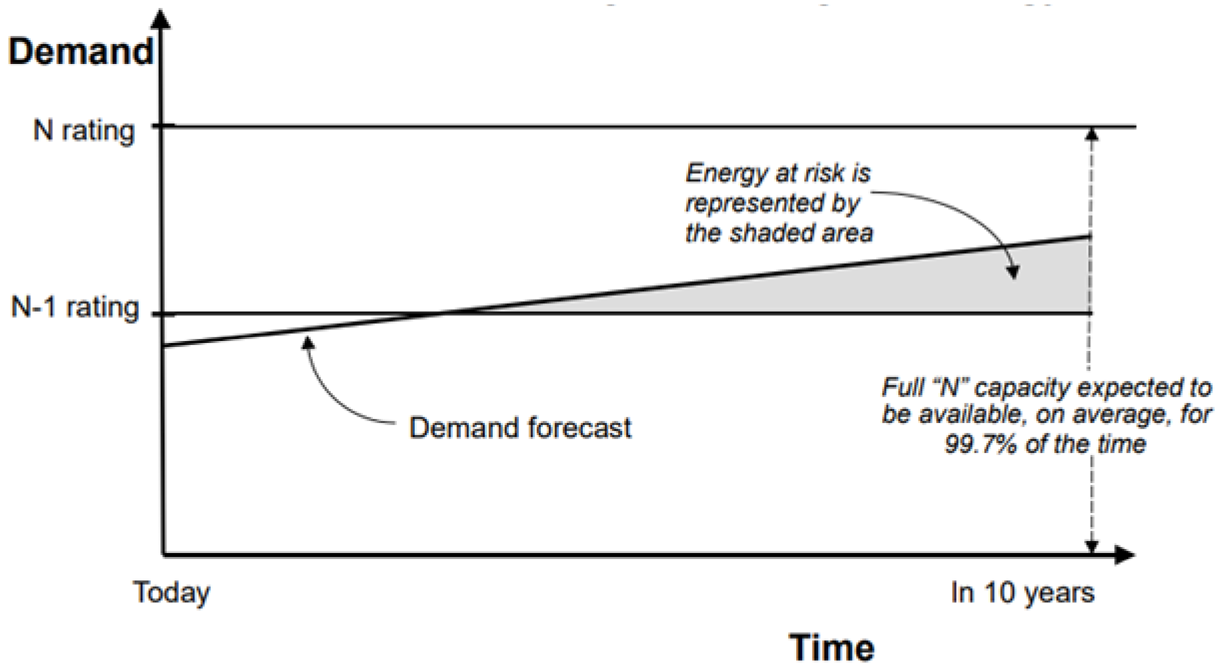


Figure 6: Relationship between N rating, N-1 rating and energy at risk

This chart is equally applicable for import and export conditions. In the case of import, maximum demands and import ratings are depicted as positive numbers, whereas in the case of export, minimum demands and export ratings are depicted as negative numbers.

While it depends on the condition of the individual asset, it is expected that:

- On average over the long term, each transformer will be unavailable for 19 hours per year.
- 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.

3.8.11. Assessing service level risk

AusNet risk-cost model quantifies the benefits of potential investment options by comparing base service level risk, assuming no risk mitigation action is taken, with the reduced service level risk assuming the credible option is place. The investment cost to implement the credible option is then subtracted from the monetised benefit to compare credible options and identify the option that maximises the net economic benefit (the proposed preferred option).

The initial screening assessments presented in the DAPR only present the base level risk, without attempting to quantify of the residual risk, and therefore net benefit, of the various options presented.

The areas of service level risk costs, and risk cost reduction benefits, that AusNet can consider include:

- Supply risk.
- Safety risk.
- Reactive replacement.
- Environment risk.
- Operations and maintenance costs.
- Losses.

3.8.12. Reliability of zone substation assets

AusNet determines the probability of asset failure from results generated using machine learning or statistical distributions fitted to heath scores. The broad categories taken into consideration by both methodologies include asset physical condition (observed and measured), asset location, duty factor (or utilisation), and asset service age.

Using the Weibull statistical distribution, future asset probability of failure and remaining life are estimated. The remaining life which is an estimate of the number of years remaining until the probability of failure reaches 10% (B10) is converted to a 5-scale likelihood score shown in Table 2. More details can be found in AMS 01-09.

Table 2: Likelihood scale

Likelihood Scale		Years remaining for asset to reach B10 (10% unreliability)
5	Very Likely	Remaining life <= 1 year
4	Likely	Remaining life > 1 year but <= 2 years
3	Possible	Remaining life > 2 year but <=3
2	Unlikely	Remaining life > 3 but < 4 years
1	Very Unlikely	Remaining life > 4 years

3.8.13. Methodology for assessing sub-transmission loop supply risk

The methodology for assessing supply risk on sub-transmission loops includes assessing the magnitude, probability and impact of loss of load (or curtailment of generation) for each sub-transmission loop. Consequential loss of supply to customers is expected if a critical sub-transmission line outage occurs whilst the loop is operating above its N-1 voltage collapse limit or above its N-1 thermal rating.

The following key data are calculated for each sub-transmission line:

- Hours at risk: For a given maximum (or minimum) demand forecast, this is the number of hours per annum that a sub-transmission loop operates beyond its firm import (or export) rating.
- Load at risk (or generation at risk): For a given maximum (or minimum) demand forecast, this is the maximum amount of load (or generation) that would be shed should a failure of a 66 kV line occur, due to an outage occurring coincident with operation of the loop beyond its N-1 import (or export) rating.
- Energy at risk: This is the amount of energy, weighted by the demand conditions considered (10% POE and 50% POE), that would not be able to be imported or exported from a sub-transmission loop, assuming an outage of a line within that loop in that particular year. This measure provides an indication of the magnitude of energy that would not be supplied to the load during import (or the amount of generation curtailment needed during export) in the unlikely event of a major network asset outage.
- Expected unserved energy: This is the energy at risk weighted by the probability of potential network asset outages and their repair times. This measure provides an indication of the amount of energy, on average, that will not be imported (or exported) in a year, considering the low probability part of the sub-transmission loop fails and is out of service.

Supply risk assessments for each individual sub-transmission loop provide estimates of energy at risk and expected unserved energy based on the demand forecasts.

3.8.14. Methodology for assessing supply risk at transmission connection points

The methodology for assessing supply risk at transmission-distribution connection points includes assessing the magnitude, probability, and impact of loss of load (or curtailment of generation) at each terminal station.

The following key data are calculated for each terminal station:

- Hours at risk: For a given maximum (or minimum) demand forecast, this is the number of hours per annum that a terminal station operates beyond its firm import (or export) rating.
- Load at risk (or generation at risk): For a given maximum (or minimum) demand forecast, this is the maximum amount of load (or generation) that would be shed should an asset failure within the terminal station occur, due to an asset outage occurring coincident with operation of the terminal station beyond its N-1 import (or export) rating.
- Energy at risk: This is the amount of energy, weighted by the demand conditions considered (10% POE and 50% POE), that would not be able to be imported or exported from a terminal station, assuming an outage of a transformer, circuit breaker or other critical asset occurs at that station in that particular year. This measure provides an indication of the magnitude of energy that would not be supplied to the load during

import (or the amount of generation curtailment needed during export) in the unlikely event of a major network asset outage.

- Expected unserved energy: This is the energy at risk weighted by the probability of potential network asset outages and their repair times. This measure provides an indication of the amount of energy, on average, that will not be imported (or exported) in a year, considering the low probability that a transformer, circuit breaker or other critical asset at the terminal station fails and is out of service.

Supply risk assessments for each terminal station provide estimates of energy at risk and expected unserved energy based on the demand forecasts.

3.8.15. Outages considered

In estimating the expected cost of zone substation asset and sub-transmission line outages, this report considers system normal condition ('N') and the first order contingency condition ('N-1') only. It is recognised that there is a significant amount of energy at risk if two lines of a sub-transmission loop or two transformers in a zone substation are out of service at the same time, due to a major outage. However, the probability of such an event occurring during peak loading periods is very low and is therefore not considered in the initial screening studies presented in the DAPR.

Where relevant, multiple contingency risk is included in detailed assessments undertaken prior to network investment.

3.8.16. Base Availability parameters

Estimates of the expected unserved energy of each zone substation and sub-transmission loop must be based on the expected reliability performance of the relevant power transformers and sub-transmission lines. The basic reliability data for power transformers and sub-transmission lines has been established and is shown in Table 3.

Table 3: Statistical availability data for zone substation power transformers and sub-transmission lines

Major plant item	Expected asset outage duration due to a major failure (hours per year)	Interpretation
Power Transformer	21.6hr/transformer/year	On average, each transformer would be expected to have one major failure every 100 years with a duration of 3 months.
Urban Sub-transmission Line	1hr/line/year	On average, each line would be expected to have one failure per annum each with a duration of one hour.
Rural Sub-transmission Line	2hrs/line/year	On average, each line would be expected to have two failures per annum each with a duration of one hour each.

3.8.17. Feasible options for meeting forecast demand

Developed options for a network limitation may include demand management or other non-network solutions, refurbishment, replacement, augmentation, or a combination of these solutions. The options for zone substation and sub--transmission loop energy at risk is economically assessed to identify feasible solutions.

Network support in the form of demand management contracts and/or embedded generation, may individually or in combination with network augmentation, form feasible options for the elimination or mitigation of constraints.

3.9. Significant changes compared to previous year

This section provides details required by schedule 5.8 (a) (5) in covering any aspects of forecasts and information provided in the DAPR that have changed significantly from those presented in the preceding year.

3.9.1. Key changes relating to REFCL plans

Following more detailed assessment of REFCL networks, and with ever-evolving REFCL technology, AusNet has updated its plans for maintaining REFCL compliance. Key changes include:

- Maintain REFCL compliance at Bairnsdale (BDL): The BDL network capacitance is relatively high, further BDL network evaluation will be required to determine future works to maintain compliance at BDL in 2025.
- Maintain REFCL compliance at Lilydale (LDL): To maintain compliance at LDL, it is proposed to add a third GFN in 2025.

In addition to BDL and LDL, the following Zone Substations are forecasted to exceed their operating limits due to capacitance growth by 2029. Network evaluation will be required to determine future works to maintain compliance.

- SMR
- WOTS
- WYK

The following feeders are forecasted to exceed their operating limits due to capacitance growth by 2029. Network evaluation will be required to determine future works to maintain compliance.

- KLK11
- WOTS25
- WYK13
- WYK24

3.9.2. Key changes relating to condition Scores

As per AMS 01-09, Condition score has been replaced by probability of failure.

4. Forecasts for the forward planning period

This section summarises the methodology applied in developing maximum and minimum demand forecasts and presents the actual and forecast demand for the five-year forward-looking period, as required under schedule 5.8 (b) of the NER.

4.1. Demand forecasting methodology

We prepare 15-year forward-looking demand forecasts annually for AusNet transmission connection assets, zone substations and distribution feeders. They are prepared for 10%, 50% and 90% Probability of Exceedance (POE) conditions, for both maximum and minimum demands, at different seasons during the year. At a high level, the following inputs are incorporated:

- Historical data, including customer numbers and rooftop PV capacity
- Forecast spatial customer numbers and rooftop PV capacity
- Historical and future estimates of electrification trends (e.g., EVs and gas electrification)
- Historical operational demands at 30-minute intervals
- Historical weather-related and solar variables (e.g., temperature, wind and solar irradiation) at 30-minute intervals
- Recorded embedded generation including wind as well as large solar generators at 30-minute intervals.

The process is described in more detail below.

4.1.1. Spatial demand forecasting process

Therea are seven key steps in the current spatial and trend analysis forecasting process:

1. Assemble historical data.
2. Forecast spatial customer numbers and rooftop PV capacity.
3. Model unitised (per capita) underlying half-hourly demand, in two separate but complementary steps, which take account of historical temperature and other factors.
4. Forecast the impact of electrification, driven by EVs and gas electrification.
5. Simulating the future.
6. Presenting the maximum and minimum demand forecasts in terms of different POEs.
7. Validate spatial demand forecasts and include post-modelling adjustments.

Each of these seven steps are explained in further detail below.

4.1.1.1. Step 1 – Assemble historical data

Customer numbers and PV capacity

Customer numbers and growth rates are a major driver of future demand, particularly spatial demand, forecasts. Historic customer numbers are extracted by asset and customer type from the tariff database and spatial asset database to provide both a launch point for the forecasts and a trend on which to inform projections over the forecast period.

Operational demand

Operational demand on various network elements (such as feeders and zone substations) is sourced from OSI-Pi, which records SCADA sensor data. After extraction, these data sets are cleansed of any abnormal readings, which can arise from data errors or temporary changes to network configuration. The resultant dataset is used as the basis for calculating the underlying demand, which is a key element of the forecast.

Embedded generation

Each embedded generator's generation data is extracted from the advanced metering infrastructure (AMI) interval database and added back into our operational demand.

Weather and solar variables

Weather data including temperature, wind speed and humidity relevant to each feeder and zone substation is extracted from DnA (AusNet's Data and Analytics Database), which is populated by postcode level time series from WeatherZone's satellite data.

The electricity generated by the rooftop PV panels depends on the panel capacity and also the solar variables (e.g., Solar irradiance). To estimate the total PV generation, we use the same data source as weather variables.

Electrification trends

The electrification trends including transport electrification---the increasing number of EVs and gas electrification, people switching from gas to electricity---are two main drivers of electricity demand in the future. In order to forecast the impact of EVs, we require detailed information on EV penetration across AusNet's network. For gas electrification, we require the number of existing gas customers, preferably by location.

4.1.1.2. Step 2– Forecast customer numbers and rooftop PV forecasts

Customer number forecasts are compiled with reference to both the historical trend in customer growth and the Victorian government's projections of structured private dwellings (SPD) in the Victoria in Future (VIF) planning publication.[8] The base forecast follows the historical trend and then is adjusted based on the VIF forecast on continuation or changing in the pace or direction of the exiting trend in the broader region. The forecasting approach here is a middle-out one, meaning that we start at the zone substation level and then follow a bottom-up approach for terminal and network level forecasts and a top-down approach for feeder and distribution substation level forecasts. This approach produces residential customer numbers, and commercial customer numbers are forecast based on the existing commercial to residential ratio.

A similar approach is applied to forecast PV capacity (and count). The only major difference is that, instead of the VIF data, we use AEMO's draft Electricity Statement of Opportunities (ESOO) assumptions to adjust our PV trends. For both residential and non-residential customers if the assumption is that PV penetration rate (PV capacity/Customer count) growth is going to increase/decrease, we apply the same to our distribution regions.

4.1.1.3. Step 3 – Model underlying half-hourly demand

The total electricity consumed by the customer is denoted as underlying demand. Historically the electricity load on the network (operational demand) and underlying demand were the same. But, over time, with the installation of rooftop solar PV panels and other embedded generators, a significant gap between these two is emerging. Our focus here is modelling the underlying demand and then estimating operational demand based on PV penetration rate and other related factors. In sum, the underlying is calculated as,

$$\textit{Underlying Demand} = \textit{Operational Demand} + \textit{Embedded Generation} + \textit{Rooftop PV Generation}$$

Where rooftop PV generation is calculated using PV capacity and solar data as,

$$\textit{Rooftop PV Generation} = \textit{PV Capacity} * \textit{PV Generation per Capacity Based on Solar Factors}$$

4.1.1.4. Step 4 – Forecasting the impact of electrification

Forecasting load from EVs

The forecast number of EVs for each network asset (Feeders, Zone Substations, Transmission Connection Point and the Distribution Network) is produced for each customer type (Residential, Small and Medium Business, and Large Business). For each component, a bottom-up approach is adopted, starting with feeders and moving up to the next network level.

The EV penetration ratio for different geographical areas are estimated by comparing customer numbers with EV sales data obtained from the Victorian Department of Transport and Planning, disaggregated to postcodes to determine the level of EV penetration across our network. Future penetration ratios are forecast using data from

[8] https://www.planning.vic.gov.au/land-use-and-population-research/victoria-in-future

AEMO's ESOO, which contains projected penetration ratios for Victoria. Our existing EV penetration ratios are increased at the same growth rate as AEMO's forecast.

The forecast method produces the following forecast EV load:

> *EV Load (kW) = Number of EVs * Share (%) in each charging profile * Load (kW) per EV in each charging profile*

The resulting EV Load (kw) for each half-hour interval for each year is adopted in the demand forecasting process.

Forecasting gas electrification load

To estimate the load that results from gas electrification, we use the below formula:

Gas-Electrification Load (kw) =

(1) Gas penetration rate (%, percentage of customers with gas connection) multiplied by

(2) Electrification rate (%, percentage of customers switching from gas to electricity) multiplied by

(3) Impact on electricity consumption (%, percentage for different seasons and for different times per day) multiplied by

(4) Base electricity consumption (kw), for different seasons and for different times per day).

The final output of this step is a half-hourly load per season (kw), which will be used in the next step, simulating the future.

4.1.1.5. Step 5 – Simulating the future

To simulate the future conditions that explain the electricity demand, we use a bootstrap method. We go through the historical observations of inter-related temperature, solar, and season variables and randomly select 1000 sets of explanatory variables. In doing so, we use a block bootstrap with variable blocks method that, first, increase the number of existing scenarios to choose from and, second, maintains the statistical characteristics of the original explanatory variables. Adjustments including the global warming impact are done on the bootstrapped series.

The bootstrapped set of explanatory variables are used to estimate underlying demand using the model developed in the previous step. We bootstrap solar variables along with the other explanatory variables and then calculate the operational demand from the estimated underlying demand. These are then used to extract seasonal maximum and minimum operational demands.

The output of the simulation step is 1000 maximum and 1000 minimum values, for each season.

4.1.1.6. Step 6 – Presenting maximum and minimum demand forecasts as POEs

The simulated maximum and minimum demands are used to extract different probabilities of exceedance (POE). POE10, POE50 and POE90 are the three most used ones for network planning purposes. Starting with the maximum demand POE10 is equal to the 90th percentile of the simulated series, where only 10% of modelled outcomes exceeded that value. In an analogous way, POE50 and POE90 are equal to 50th and 10th percentiles of the simulated maximum demand, respectively.

In the case of the minimum demand, however, there is a slight difference in definition. POE here means the probability of operational demand going lower than a specific value. Therefore, POE10, POE50 and POE90 are exactly 10th, 50th and 90th percentiles of the simulated minimum demands, respectively. Whilst on face value this is a contradiction in terms (probability of exceedance reflects the chance of demand being lower than the value), this approach retains the intuition that a POE10 scenario is describing an outcome with a 10% chance of being more severe than the forecast (e.g. even lower demand than a minimum demand forecast predicts).

4.1.1.7. Step 7 – Validate spatial demand forecasts and post modelling adjustments

Regional network planning engineers in conjunction with the sub-transmission planning engineer validate the relevant forecasts. Validation involves magnitude checks and trend line checks informed by knowledge of the loadings and network configuration changes recently completed and pending. Adjustments are undertaken to improve the accuracy of the forecast by addressing factors such as:

- large customers (above 1MVA) that are known to have connected recently or will connect in the near term (i.e. block loads)
- impact of known network projects that have recently been undertaken or are in train such as feeder reconfigurations

- Inconsistencies in AMI data that lead to offsets in the final forecast.

We apply post model adjustments for block loads, assessing actual connection requests for loads over 1MVA that are well progressed and are expected to proceed.

4.2. Network Capacitive Current Forecasting Methodology

To ensure the ongoing compliance of the REFCLs (refer Section 4.9.1), a forecast of network capacitive current was developed. The forecasts were prepared following a capacitive current forecasting methodology developed by AusNet with input from The Centre for International Economics (The CIE).

The forecasting methodology considers the following components which are considered the primary drivers of capacitive current growth:

- Determine the length of underground and overhead cable per new customer
- Determine types of customers (residential, commercial, and industrial)
- Historical cable growth trend per customer class on each feeder
- Annual customer number forecast is used directly for each feeder and customer class, this would more accurately align the cable requirements to the timing of expected customer numbers
- Considering actual cable types and lengths from the existing network
- Transformer capacitance even though minimal in comparison to cables was added based on existing installed transformers

To implement this approach further work by AusNet has also been conducted to check the accuracy of model by comparing the model analysis with current actual outcomes by carrying out the summation of capacitance from individual cable types and associated lengths that aligns to the overall measured capacitance.

The analysis undertaken to derive the numbers has provided a more robust relationship between customer numbers and cable requirements. Furthermore, the model incorporates an important feature to reflect changes in capacitance due to introduction of proposed isolation transformers on selected feeders which will have an impact on reducing capacitance hence forecast is adjusted accordingly.

4.3. Network Capacitive Current Forecasts

Table 5 presents the capacitance current forecast for each REFCL zone substation. The grey shaded cells highlight where the capacitance forecast exceeds the arc suppression coil (ASC) limits for the number of ground fault neutralisers (GFNs) installed at the zone substation. For zone substations that do not yet have a REFCL installed and are therefore yet to have their ASC limit determined through field measurement, an ASC limit of 100A has been assumed.

Table 5: Capacitance Forecast Results (as at December 2024)

ZSS	Region	No. of feeders	No. of REFCLs	Bus ID	ASC Limit	2023 Capacitive Current	2028 Capacitive Current
BDL	East	8	2	BDL BUS 3	158	111	136
				BDL BUS 4	128	131	145
BGE	Central	6	2	BGE BUS 1	98	82	96
				BGE BUS 2	135	112	112
BGEBSY	Central	1	1	BGEBSY	104	76	79
BN	Central	5		BN BUS 1	140	30	33

			1[9]	BN BUS 2	140	64	78
BNBVT	North	1	1	BNBVT BUS 1	71	71	73
BWA	North	4	1	BWA BUS 2	128	69	76
ELM	Central	8	2	ELM BUS 2	151	119	125
				ELM BUS 3	133	95	100
FGY	Central	10	2	FGY BUS 1	138	12	17
				FGY BUS 2	138	56	66
				FGY BUS 3	73	30	32
KLK	Central	3	1[13]	KLK BUS 1	140	92	106
KLO	Central	2	2[13]	KLOKDB	140	21	38
				KLOKBV		50	74
KMS	North	2	1	KMS BUS 1	144	78	87
LDL	Central	8	2	LDL BUS 1	133	114	127
				LDL BUS 2	138	118	134
LLG	Central	3	1[13]	LLG BUS 1	140	91	95
MOE	East	8	2	MOE BUS 1	79	57	60
				MOE BUS 2	90	69	74
MSD	North	8	1	MSD BUS 1	128	72	83
MYT	North	4	1	MYT BUS 1	81	56	62
				MYT BUS 2			
RUBA	North	3	1	RUBA BUS 1	83	71	78
				RUBA BUS 2			
RWN	Central	7	1	RWN BUS 2	138	115	120
				RWN BUS 3			
SLE	East	4	1[13]	SLE BUS 1	140	115	136
				SLE BUS 3			
SMR	North	6	2	SMR BUS 1	79	57	63
				SMR BUS 2	115	100	116
WGI	East	8	1	WGI BUS 2	107	75	82
				WGI BUS 3	115	77	94
WN	North	7	2	WN BUS 1	119	100	106
				WN BUS 2	151	92	97
WOTS	North	6	2	WOTS BUS 1	121	91	100

[9] Advanced Residual Current Compensation (ARCC) unit

				WOTS BUS 2	167	78	86
WYK	Central	4	2	WYK BUS 1	87	101	109
				WYK BUS 2	119	93	101

4.4. Five-year forecasts

The asset loading forecasts presented herein are for the five-year forward planning period. They address summer and winter separately and provide observations (actual loadings) from 2024 and forecasts for the five-year forward planning period of 2025-2029.

50% POE and 10% POE represents the probability of exceedance demand. Each demand is expressed as the probability or the likelihood the forecast would be met or exceeded. For example, a 10% probability of exceedance (POE) demand, represented in the table as 10% POE, implies there is a 10% probability of the actual demand going beyond the forecast maximum (or minimum) demand values[10].

4.4.1. Maximum and minimum demand forecasts at the transmission-distribution connections points

Schedule 5.8 (b)(2)(i) of the NER requires load forecasts at the transmission-distribution connections points. However, clause 5.13.2(d) stipulates that a DNSP is not required to include in its DAPR information required in relation to transmission-distribution connection points if it is required to do so under jurisdictional electricity legislation.

DNSPs in Victoria are required, under clause 19.3 of the Victorian EDCoP, to publish load forecasts at the transmission-distribution connection points in the Transmission Connection Planning Report (TCPR). The current TCPR covers the period of 2024-2033 and to avoid duplication the forecasts are generally not repeated in this report.

Schedule 5.8 (b)(2A)(i) of the NER requires forecast use of distribution services by embedded generating units to be published:

- At the transmission-distribution connection points (Table 6),
- for sub-transmission lines (Table 49); and
- for zone substations (Table 52).

4.4.2. Maximum demand forecasts for sub-transmission lines

This section provides details required by schedule 5.8(b)(2)(ii) of the NER in covering load forecasts for sub-transmission lines and provides the additional information specified by (iv) to (ix). Sub-transmission lines are grouped into normally interconnected loops or circuits.

Table 48 from the Appendix E.1.1 present:

- The firm capacity of sub-transmission loops during import conditions (i.e., the 'N-1' import rating), being the capacity of the loop with the worst-case line outage and the import rating being reached on one of the remaining lines.
- The historical actual maximum demand of the line or loop (non-diversified aggregate loop zone substation loading), and the line or loop power factor at the time of maximum demand; and
- The maximum demand forecasts for winter and summer inclusive of line losses under single contingency (non-diversified aggregate loop zone substation 10% POE loading).

Table 50 from the Appendix E.1.3 presents:

- The total capacity of the AusNet sub-transmission lines or loops during import conditions (i.e., the 'N' import rating).

[10] Regional Demand Definition, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Generation-and-Load

- The load transfer capacity (to zone substations outside the 66 kV line or loop at time of need, 10%POE).
- The embedded generation capacity.
- The estimated hours per year that 95% of the line or loop maximum demand is expected to be reached in winter and summer.

4.4.3. Maximum demand forecasts for zone substations

This section provides details required by schedule 5.8(b)(2)(iii) of the NER in covering load forecasts for zone substations and provides the additional information specified by (iv) to (ix).

Maximum demand forecasts for zone substations are provided in Table 51 in Appendix E.1.4 and additional information in Table 53 in Appendix E.1.6.

Table 51 presents:

- The total capacity of the AusNet zone substations during import conditions (i.e., the 'N' import rating), being the total station nameplate capacity.
- The firm capacity of the zone substation during import conditions (i.e., the 'N-1' import rating), being the capacity of the station with the worst-case transformer outage and the import rating being reached on one of the remaining transformers.
- The historical actual maximum demand of the zone substation.
- The power factor at the time of maximum demand; and
- The maximum demand forecasts (10% POE) for winter and summer.

Table 53 presents:

- The load transfer capacity (to other zone substations at time of need, 10%POE);
- The embedded generation capacity; and
- The estimated hours per year that 95% of the maximum demand is expected to be reached in winter and summer.

4.4.4. Minimum demand forecasts for transmission connection assets

This section provides details required by schedule 5.8(b)(2A)(i) of the NER in covering forecast use of distribution services by embedded generating units at transmission-distribution connection points and provides the additional information specified by (iv) to (vii).

Table 6 presents:

- The total capacity of the AusNet terminal stations during export conditions (i.e., the 'N' export rating);
- The firm capacity of the terminal stations during export conditions (i.e., the 'N-1' export rating), being the capacity of the station with the worst-case transformer outage and the export rating being reached on one of the remaining transformers;
- The historical actual minimum demand of the terminal station;
- The power factor at the time of minimum demand;
- The 10% POE minimum demand forecasts for each year. A negative minimum demand represents an export condition; and
- The estimated hours per year that 95% of minimum demand is expected to be reached in the year.

Table 6: AusNet Terminal Stations – Historic and Forecast Minimum Demand (MVA) and Export-Related Information – All Year

Terminal Station	'N' Export Rating (MVA)	'N-1' Export Rating (MVA)	Minimum Demand (MVA)							
			Actual		10% POE					
			pf	2024	2025	2026	2027	2028	2029	95% Hours
CBTS	450	300	-0.95	-76.1	-122.7	-150.7	-176.2	-198.2	-214.3	28
ERTS*	*	*	*	*	*	*	*	*	*	*
GNTS	248	125	1.0	-191.8	-210.9	-216.4	-221.1	-225.2	-228.3	48
MBTS	50	50	0.93	-12.5	-15.0	-16.5	-17.6	-18.6	-19.3	36
MWTS	465	300	0.92	-94.5	-113.9	-131.5	-145.3	-155.7	-162.2	34
RWTS22	150	75	-0.90	7.21	-4.7	-6.1	-8.3	-10.6	-12.5	5.5
RWTS66	600	450	1.0	43.4	-34.9	-46.5	-58.1	-67.6	-74.8	14.5
SMTS	450	225	0.91	-67.0	-89.9	-112.3	-129.2	-142.8	-152.0	54
TSTS*	*	*	*	*	*	*	*	*	*	*
TTS*	*	*	*	*	*	*	*	*	*	*
WOTS	150	75	1.0	-11.9	-16.2	-19.2	-21.6	-23.3	-24.4	14

*Data for shared terminal stations ERTS, TTS and TSTS are prepared by other DNSP's and are covered in the 2023 TCPR.

4.4.5. Minimum demand forecasts for sub-transmission lines

This section provides details required by schedule 5.8(b)(2A)(ii) of the NER in covering forecast use of distribution services by embedded generating units for sub-transmission lines and provides the additional information specified by (iv) to (vii). Sub-transmission lines are grouped into normally interconnected loops or circuits.

Table 49 from the Appendix E.1.2 presents:

- The total capacity of the AusNet sub-transmission lines or loops during export conditions (i.e., the 'N' export rating);
- The firm capacity of sub-transmission loops during export conditions (i.e., the 'N-1' export rating), being the capacity of the loop with the worst-case line outage and the export rating being reached on one of the remaining lines;
- The historical actual minimum demand of the line or loop (non-diversified aggregate loop zone substation loading);
- The line or loop power factor at the time of minimum demand;

- The 10% POE minimum demand forecasts for each year. A negative minimum demand represents an export condition; and
- The estimated hours per year that 95% of the line or loop minimum demand is expected to be reached in the year.

4.4.6. Minimum demand forecasts for zone substations

This section provides details required by schedule 5.8(b)(2A)(iii) of the NER in covering forecast use of distribution services by embedded generating units at zone substations and provides the additional information specified by (iv) to (vii).

Table 52 provided in Appendix E.1.5 presents:

- The total capacity of the AusNet zone substations during export conditions (i.e., the 'N' export rating);
- The firm capacity of the zone substation during export conditions (i.e., the 'N-1' export rating), being the capacity of the station with the worst-case transformer outage and the export rating being reached on one of the remaining transformers.
- The historical actual minimum demand of the zone substation.
- The power factor at the time of minimum demand;
- The 10% POE minimum demand forecasts for each year. A negative minimum demand represents an export condition; and
- The estimated hours per year that 95% of minimum demand is expected to be reached in the year.

4.5. Future assets

Consistent with the requirements from schedule 5.8 (b)(3) of the NER, this section provides details regarding forecasts of future transmission-distribution connection points (and any associated connection assets), sub-transmission lines and zone substations, including for each future transmission-distribution connection point and zone substation.

4.5.1. Transmission to distribution connection points

Clause 5.13.2(d) of the NER stipulates that a DNSP is not required to include in its DAPR information required in relation to transmission-distribution connection points if it is required to do so under jurisdictional electricity legislation. DNSPs in Victoria are required by the Victorian EDCoP Clause 19.3 to publish load forecasts at the transmission-distribution connection points in the TCPR covering the period 2025-2034[11].

In mid-2021, AusNet commenced a Regulatory Investment Test for Transmission (RIT-T), jointly with United Energy and in consultation with AEMO, to assess options to mitigate the thermal loading risk on the Cranbourne Terminal Station (CBTS) 220/66 kV connection assets transformers. This RIT-T process was completed in late 2022, with the Project Assessment Conclusions Report (PACR) published in mid-October 2022. The identified preferred option involved the installation of a fourth 220/66kV 150MVA transformer at CBTS. However, due to a material change in one of the inputs (option costs), Ausnet and United Energy have re-commenced the RIT-T with the Project Specifications Consultation Report (PSCR) being published in October 2024. Following conclusion of the PSCR consultation period (10th January 2025), AusNet and United Energy will, having regard to any submissions received on the PSCR, prepare and publish a project assessment draft report (PADR) in early 2025.

In late 2023, AusNet Services had identified load at risk at South Morang Terminal Station (SMTS). In early 2025, AusNet Services will be initiating this Regulatory Investment Test for Transmission (RIT-T) to evaluate options for maintaining reliable power transformation services at SMTS.

As described in Section 8.1.6. AusNet commenced a Regulatory Investment Test for Transmission (RIT-T) in January 2024 to investigate and evaluate options to address constraints in the Wodonga Terminal Station (WOTS) sub-transmission (66 kV) system which are restricting new renewable generation connections. It has been identified that

[11] A copy of the 2023 Transmission Connection Planning Report and Terminal Station Demand Forecasts can be viewed at AusNet website: AusNet - Rosetta Data Portal (ausnetservices.com.au).

the existing two 330/66k/22kV connection asset transformers at WOTS are not capable of handling the reverse flow associated with the significant number of renewable generation connection enquiries in this area. As such, the preferred option identified in the Project Assessment Draft Report (PADR) published in July 2024, involves the commissioning of the spare 330/66/22kV transformer at WOTS.

4.5.2. Sub-transmission lines

As described in Section 8.1, AusNet has published the following Regulatory Investment Tests (RITs) to investigate and evaluate options to address constraints which are restricting new renewable generation connections into AusNet's sub-transmission and distribution network:

- Morwell East Area: AusNet commenced a Regulatory Investment Test for Distribution (RIT-D) in January 2024 and evaluated options involving the augmentation of the Morwell Terminal Station (MWTS) to Traralgon Zone Substation (TGN) 66kV subtransmission section as it was identified that this portion is a major bottleneck for connecting new generation to the Morwell East network. For more details see Section 8.1.6.
- Morwell South Area: AusNet commenced a Regulatory Investment Test for Distribution (RIT-D) in January 2024 and evaluated options involving the augmentation of the Morwell Terminal Station (MWTS) to Leongatha (LGA) 66kV subtransmission section as it was identified that this portion is a major bottleneck for connecting new generation to the Morwell South network. For more details see Section 8.1.7.
- Wodonga – Barnawartha in North-Eastern Victoria: AusNet commenced a Regulatory Investment Test for Transmission (RIT-T) in January 2024 and evaluated options involving the augmentation of the Wodonga Zone Substation (WO) to Barnawartha (BWA) 66kV subtransmission section as it was identified that this portion is a major bottleneck for connecting new generation into this part of the network. For more details see Section 8.1.6.

AusNet has plans for Regulatory Investment Tests for Distribution (RIT-Ds), to investigate options to secure supply and enable connections in the following loops;

- The Cranbourne Terminal Station (CBTS) to Lysterfield (LYD) to Narre Warren (NRN) to Pakenham (PHM) to Officer (OFR) to Berwick North (BWN) to Lang Lang (LLG) to Clyde North (CLN) 66 kV loop as described in Section 6.1.1.
- The Maffra, Traralgon, Sale and Bairnsdale Switching Station (MFA-TGN-SLE-BDSS) 66kV loop, emanating from Morwell Terminal Station (MWTS).

The East Gippsland Supply risk RIT-D commenced in 2020 and submissions were received in 2021. The RIT-D was closed at the end of 2021. Further evaluation of the East Gippsland will be conducted to determine a more economical solution and if deemed necessary, this project will undergo a reassessment through the RIT-D process.

4.5.3. AusNet Zone Substations

In the next five years, AusNet plans to augment ten existing zone substation (four for maintain supply capacity due to demand growth and six to maintain REFCL compliance due to network capacitance growth), undertake major asset replacement within eight existing zone substations. In addition, AusNet plans to address voltage performance issues across the electricity distribution (ED) network at eleven zone substations and four HV feeder locations.

The zone substation where capacity augmentation is proposed is:

- Clyde North Zone Substation (CLN): Under 10% POE conditions, the loading at CLN is forecast to exceed acceptable levels. A RIT-D assessment has been undertaken, and a third 20/33 MVA transformer and third 22 kV switchboard at the station are planned to be installed by the end of December 2025.
- Wollert region: Anticipated substantial rises in power demand are projected for the Wollert region. The 2016 census recorded a population of 9,060 in Wollert, which surged to 24,407 by 2021, reflecting an average annual growth rate of around 22%. A proposed singular remedy, likely entailing the establishment of a new zone substation in Wollert, aims to mitigate capacity constraints at the Doreen Zone Substation, Epping Zone Substation, and South Morang Zone Substation. For more details refer to section 9.16.
- Pakenham South area: State planning guidelines within the 'Victoria in the Future' publication have forecast significant future industrial development in the Pakenham South area. A proposed singular remedy, likely entailing the establishment of a new zone substation in Pakenham South, aims to mitigate capacity constraints at Officer and Pakenham Zone substations. For more details refer to section 9.10.
- Wonthaggi (WGI): The Wonthaggi (WGI) Zone Substation, a Rapid Earth Fault Current Limiter (REFCL) site, comprises three 13.5MVA 66/22kV transformers supplying two buses, with specific concerns regarding Bus 2 and Bus 3. Currently interconnected, the buses share load efficiently but will separate in 2024 for REFCL

compliance, resulting in existing transformers being unable to meet the anticipated load growth. The installation of individual REFCL Ground Fault Neutralisers (GFN) will divide bus operation, posing risks such as potential overloading and a lack of N-1 capability. Zone substation augmentation will be required by 2027.

The nine zone substations where major asset replacement is expected in the next five-year period, due to deteriorated assets, are:

- Bayswater (BWR), Benalla (BN), Maffra (MFA), Thomastown (TT), Traralgon (TGN), Warragul (WGL), Watsonia (WT), Numeralla (NLA) and Kilmore South (KMS)

The twenty-two REFCL zone substations include Kinglake (KLK), Woori Yallock (WYK), Kilmore South (KMS), Wangaratta (WN), Rubicon A (RUBA), Barnawartha (BWA), Seymour (SMR), Myrtleford (MYT), Wonthaggi (WGI), Benalla (BN), Ringwood North (RWN), Eltham (ELM), Ferntree Gully (FGY), Belgrave (BGE), Lilydale (LDL), Bairnsdale (BDL), Moe (MOE), Sale (SLE), Mansfield (MSD), Wodonga Terminal Station 22 kV switchyard (WOTS), Lang Lang (LLG), and Kalkallo (KLO). Out of these two zone substations require augmentation due to capacitance growth in order to maintain compliance in 2024. The two zone substations are Lilydale (LDL) and Bairnsdale (BDL).

Of the twenty-two REFCL zone substation sites, as at 11 December 2024, all sites are compliant and available for service.

Four zone substations including FGY, SMR, WOTS and WYK are forecasted to exceed their operating limits due to capacitance growth in the coming years. Network evaluation will be required to determine future works to maintain compliance. Due to reaching capacity and in order to maintain compliance two sites, Bairnsdale (BDL) and Lilydale (LDL) will require further augmentation next year. Remote REFCLs and 3rd GFN solutions are being considered.

The zone substations included in the voltage management program are:

- Watsonia (WT), Kalkallo (KLO), Ringwood Terminal (RWT22), Lysterfield (LYD), Narre Warren (NRN), Berwick North (BWN), Cranbourne (CRE), Leongatha (LGA), Kilmore South (KMS), Bright (BRT), Traralgon (TGN)

As part of AusNet proactive voltage management program that aims to address voltage performance issues across the ED network, eleven zone substations and four HV feeder locations have been selected for Voltage Regulatory Relay replacement project within this EDPR period. The installation of residential solar PV systems in the ED network exceeds the forecast used in the current regulatory period by approximately 25 per cent, which increases the challenges in maintaining voltage within the EDCoP. The scope of the VRR replacement program has been developed leveraging advanced smart meter data to assess the ED network and provide a detailed, site-specific economic analysis. As the penetration of solar generation is increasing, more feeders are likely to experience reverse power flow and the existing VRRs with uncompensated settings alone are not sufficient to regulate the voltage for both maximum and minimum (including reverse power flow) loading scenarios expected throughout the day.

Ausnet is committed to introduce innovative ways of managing voltage and Dynamic Voltage Management, and trials will be carried out within this EDPR period to evaluate its benefits and rolling out to more locations. The preliminary comprehensive studies around all sites of the network are nearing completion to select most preferred site for trial.

4.6. Forecasts of the DNSP performance against STPIS reliability targets

This section provides details required in schedule 5.8 (b)(4) of the NER covering forecasts of performance against reliability targets in the Service Target Performance Incentive Scheme (STPIS). Details of the STPIS are found at the Australian Energy Regulators website[12].

Table 7 shows AusNet network reliability performance against STPIS targets for the FY22/23 (1/7/2022 – 30/6/2023) and the new Financial Year period FY23/24 (1/7/2023 – 30/6/2024).

[12] A copy of the Electricity Distribution Network Service Providers' Service Target Performance Incentive Scheme can be viewed at the Australian Energy Regulator's website: http://www.aer.gov.au/

AusNet has achieved improved performance against SAIDI and SAIFI targets in recent years. This is due to an increase in reliability centred capital investments along with somewhat favourable weather conditions. This is a good outcome for customers who have received improved reliability performance.

Table 7: AusNet network reliability performance against STPIS targets

Measure	Feeder Class	5yr	FY22/23		FY23/24		FY24/25
		Target	Total	Net[16]	Total	Net[16]	Net[13]
Unplanned SAIDI	Urban	87.190	84.097	75.525	392.035	110.388	81.530
	Rural Short	195.160	244.405	195.819	1091.926	169.571	223.000
	Rural Long	293.692	413.267	351.194	1605.178	281.800	368.242
Unplanned SAIFI	Urban	0.891	0.669	0.621	1.438	0.984	0.771
	Rural Short	2.007	1.554	1.380	2.189	1.245	1.927
	Rural Long	2.628	2.629	2.307	3.917	2.020	2.658
Unplanned MAIFI	Urban	2.817	3.089	3.060	3.452	2.949	2.707
	Rural Short	5.657	4.997	4.833	4.799	4.220	5.747
	Rural Long	9.920	9.799	9.581	7.610	6.534	9.780

4.7. Factors that may have material impact on distribution network

This section provides details of factors other than demand growth that may have a material impact on the AusNet network. These factors include network capacitive current, fault levels, voltage levels, other power system security requirements, quality of supply, ageing and potentially unreliable assets. The contents of this section cover schedule 5.8 (b)(5) of the NER.

- **Network capacitive current:** With the implementation of rapid earth fault current limiter (REFCL) technology, the size and balance of network capacitance has become increasingly important and has and is expected to continue to be a primary driver of network augmentation into the future.
- **Fault levels**: Fault levels in certain areas of the distribution network are reaching its allowable limits due to connection of new embedded generators and network augmentations.
- **Voltage levels**: Voltage levels are generally maintained within the distribution code limits. However, in certain areas voltages are outside code limits and corrective actions are taken when these violations are observed. A survey undertaken by an external agency shows that the steady state voltage received by customers are generally closer to the upper boundary of the allowable limits and need to be carefully managed.
- **Other security system requirements**: There are number of zone substations fed from a single sub transmission line and/or single transformer or un-switched zone substations. These sites will have supply

[13] End of year forecast, after removing exclusions, based on year-to-date.

security issues when a credible contingency occurs. Improvements in system security for these sites will be considered when an augmentation is proposed either due to increase loading or ageing assets.

- **Quality of supply to other network users**: Comprehensive system studies are carried out prior to connecting disturbing loads to determine suitability of the proposed new customer connections an corrective actions are taken where necessary to maintain quality of supply to all customers within the code requirements.
- **Ageing and increasing probability of failure:** AusNet Asset Management Strategy outlines the process undertaken to manage ageing and increasing probability of failure of assets.

These factors are discussed in more detail below:

4.7.1. Network capacitive current

The installation and application of REFCL technology are governed by two key pieces of legislation:

- Electricity Safety Act 1998; and
- Electricity Safety (Bushfire Mitigation) Regulations 2013.

The Electricity Safety (Bushfire Mitigation) Regulations 2013 defines part of the "Required Capacity" as, in the event of a phase-to-ground fault on a polyphase electric line, the ability to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone station for high impedance (25.4 kΩ) faults to 250V within 2 seconds.

For the REFCL to operate within the criteria, the magnitude of network dissymmetry (or network capacitive balance) must be reduced significantly and maintained within a narrow band. Moreover, the size (total capacitance) of the network must also be limited.

Compliance is achieved through the sensitivity equation:

$$R_f = \frac{U_{ph}}{I_{CE}}\left[\frac{\left(\frac{1}{U_{ENt}} - 1\right)}{d + k}\right]$$

Where:

R_f (fault resistance) is legislated to 25.4kΩ

Uph (phase voltage) is fixed at 12.7kV

U_{ENt} (trigger neutral voltage) is 3 times U_{EN} (standing neutral voltage) in per unit d

(damping) is a network construction parameter (resistive leakage current) in per unit

k (dissymmetry) is mostly the capacitive imbalance in per unit

ICE (total capacitance to earth) is the tune point in Amps

Of the equation, the two variables that are easiest to manipulate are k (capacitive balance) and I_{CE} (network capacitance size).

k (capacitive balance)	Should be large enough for the REFCL to tune (typically greater than 0 mA)
	Should be small enough to detect to allow the REFCL to detect faults less than 80mA (but can be extend if I_{CE} is reduced)
	Should be balanced by remote controlled switching section, so the network stays compliant, and the ground fault neutraliser does trip the feeder if a field device operates
I_{CE} (network capacitance size)	Should not be less than 20A because coil cannot tune well below this value.

In general, and from a forward planning perspective, should not be more than 100A, although the actual limit is location specific because its affect by network damping and the level of capacitive balance.

A capacitance forecast has been developed to assist in determining when the network capacitive current is nearing the limit of the sensitivity equation that defines the ability to achieve compliance and indicates augmentation is required.

4.7.2. Fault Levels

Fault level at any given point of the electric power supply network is the current that would flow in case of a short circuit fault at that point. The purpose of fault level calculations is:

- For selecting short circuit protective devices of adequate short circuit breaking capacity;
- For selecting circuit breakers & switches of adequate short circuit making capacity;
- For selecting busbars, busbar supports, cables & switches, designed to withstand thermal & mechanical stresses because of short circuit;
- To carry out current based discrimination between protective devices; and
- To indicate the level of system strength and a location's ability to facilitate new generation.

Fault levels are determined utilising numerous factors including:

- Installed generation;
- Impedance of transmission and distribution network assets;
- Connected load including motors; and
- Network voltage.

Switchgear, plant, and lines in an electrical network have a maximum allowable three phase and single-phase to ground short circuit fault level rating. The EDCoP also specifies that embedded generators must not cause fault levels to exceed levels in the distribution network specified in Table 8. Fault levels at some terminal station 66 kV and 22 kV buses exceed these limits by agreement in Use of System Agreements for those stations. Fault level studies are carried out to ensure that the distribution system is operated within plant ratings and EDCoP requirements.

Table 8: Distribution System Fault Levels

Voltage Level (kV)	System Fault Level (MVA)	Short Circuit Level (kA)
66	2500	21.9
22	500	13.1
11	350	18.4
6.6	250	21.9
<1	36	50

The requirements place an obligation on system planners to ensure that:

- Any augmentation to the network will maintain short circuit fault levels within allowable limits.
- The addition of distributed generation or embedded generation which increases fault levels is assessed for each new connection to ensure limits are not infringed.
- When an augmentation such as a new zone substation, line upgrade or new transformer is contemplated that fault levels are checked to ensure that they do not exceed the allowable limits.
- Fault levels are commonly managed by splitting buses at stations when fault level would otherwise exceed limits.

4.7.3. Network Fault Level Issues

When fault levels reach the designed limits as outlined in the EDCoP (ref Table 8), the following corrective actions will be investigated, and appropriate fault level mitigation measured will be taken to comply with the code. These corrective actions include:

- Install 66 kV line reactors or 22 kV transformer reactors or 22 kV feeder reactors to reduce the fault levels.
- Shift the 22 kV feeder open points to transfer generation to a neighbouring station with a higher fault level margin.
- Operate the station with a normally open bus tie.
- Operate the station with one transformer as a hot standby.

As noted previously, comprehensive network studies are undertaken prior to connecting embedded generators and the proponents are advised of the corrective actions required to maintain fault levels within safe limits.

Fault Levels at a number of stations are reaching the allowable limits as described in Table 8 above. The stations with fault level issues are listed below, including the mitigation arrangements.

4.7.3.1. Watsonia Zone (WT) Substation Fault Level Issue

Watsonia zone substation has a fault level mitigation arrangement where one transformer is maintained as a hot spare and does not share load with the other two transformers. This arrangement will continue into the foreseeable future to maintain fault levels within limits on 22 kV switchgear (assets).

4.7.3.2. Morwell Terminal Station (MWTS) Fault Level Issue

Similarly, 66 kV buses at MWTS have been opened between Buses 1 and 2 and between 2 and 3 to maintain fault levels within allowable limits.

4.7.3.3. Ringwood Terminal Station (RWTS) Fault Level Issue

Series reactors have been installed at RWTS on each of the 22 kV feeders to maintain fault levels below 13.1 kA. A new Neutral Earth Resistor (NER) has also been installed to further reduce Phase to Ground fault levels.

4.7.3.4. Epping Zone Substation (EPG) Fault Level Issue

As part of a network support initiative to manage loads supplied from DRN zone substation, the Wollert Power Station connection is being relocated to DRN. Due to this generator relocation from EPG zone substation to DRN zone substation, the previously noted EPG 22 kV bus fault level issue is expected to be resolved in 2023.

4.7.4. Voltage Levels

Electricity distributors are obliged to maintain customer voltages within specified limits. Clause 20.4 of the Victorian EDCoP specifies the voltage levels that must be maintained at the meter or the point of supply to the customer's electrical installation.

Network voltage can be affected due to a number of factors including:

- Customer load
- Generation of electricity into the network (at various voltage levels)
- Transmission and distribution line impedances
- Transformer impedances
- Transformer and regulator tap positions
- Capacitors in the network (or other reactive power plant)
- Seasonal loading behaviour
- Non-compliance of inverter settings

Voltage levels from the respective connection points to customers' point of connections are managed by application of on-load-tap changes in zone substation transformers, reactive power compensations at various points in the network; line voltage regulators and utilising off-load taps in distribution transformers.

Due to increased penetration of solar PV over the last decade, maintaining voltage within EDCoP limits at customers' point of connections has become a challenge because of reverse power flows. However, these issues are monitored, and corrective actions are taken when necessary to minimise the impact on customers.

AusNet actively undertakes works to improve supply quality for customers connected to its distribution network. These works are carried out when voltage issues are identified through AMI meters or to respond to customer complaints regarding supply voltage. The steady state voltages monitored through dedicated power quality monitoring instruments and customers' AMI meters have revealed that there are many customers experiencing voltages close to the upper limit of the EDCoP requirements. As part of network planning activity, steady state voltages are brought back within the EDCoP limits where possible.

4.7.5. Negative Sequence Voltage

The following sub-transmission loops have been identified as having negative sequence voltage issues:

- East Gippsland sub-transmission network – zone substations NLA and CNR.
- SMTS–KLK–Rub A–KMS sub-transmission loop – zone substations KLK, Rub A and SMR.
- South Gippsland sub-transmission loop – zone substations FTR, LGA, WGI and PHI.
- GNTS–BN–MSD loop – zone substations MSD and MJG.
- WOTS–WO loop – zone substation WO.
- RWTS–RWN loop – zone substation RWN.
- RWTS–LDL–WYK loop – zone substation LDL.
- RWTS–BRA–BWR loop – zone substations BRA and BWR.

Although these loops were identified as having negative sequence voltage issues, AusNet has not received complaints from customers supplied from these loops and zone substations. However, several measures have been taken to minimise the negative sequence voltage deviation, including implementing transpositions on 66 kV subtransmission lines and load balancing.

4.7.6. Other power system security requirements

The NER clause 4.3.4 (g) – (i) requires DNSPs to plan and operate their networks in accordance with network stability guidelines published by AEMO. AusNet carries out its planning and network operations in accordance with these guidelines.

4.7.7. Quality of supply to other network users

AusNet undertakes system studies as part of the connection process when connecting disturbing loads such as embedded generators or large industrial customers, to investigate the impact on quality of supply to other network users. The network studies described above can also be undertaken by a consultant nominated by the customer in consultation with AusNet. The required network data will be provided to the respective consultant and the final report will be reviewed by AusNet and approved before the customer is allowed to be connected.

4.7.8. Ageing and Increasing Probability of Failure of Assets

AusNet has an ageing electricity distribution network, with a significant proportion of these assets approaching the end of their technical lives. Our asset management plans include specific tasks and activities required to optimise costs, risks and performance of the assets.

AusNet uses ISO 31000 Risk Management Guideline to manage the fleet of assets. The major assets are assessed to determine the likelihood of failure and the cost of failure. The results of the analysis are depicted on a 5x5 Risk matrix with a likelihood scale 1 to 5 (1 being very unlikely and 5 very likely) and a consequence scale 1 to 5 (1 being insignificant and 5 being catastrophic).

Risk mitigation activities, or treatments, are required to maintain risk by targeting reduction of PoF or CoF depending on the nature of the risk. Mitigation measures include asset replacement, asset refurbishment, inspections, testing or system redesign, and are achieved through capital projects or operational expenditure. Risk treatment options are described in the section on "Risk Treatment' in AMS 01-09.

Some examples of the risk mitigation activities include:

- Condition monitoring techniques are utilised to detect early stages of asset degradation before poor condition becomes a significant risk to the safety of personnel, network reliability and the environment. A range of condition monitoring techniques is used to monitor and analyse the mechanical and electrical condition and performance of the various asset classes to accurately forecast future augmentation and replacement requirements.
- Zone substation plant and equipment is subject to a combination of periodic and duty cycle inspection and maintenance programs derived from manufacturer recommendations and industry experience. Line assets are subject to cyclic inspection and other techniques such as automated image processing using high resolution aerial images, Smart Aerial Imaging and Processing (SAIP), for conductor condition assessment.

4.7.9. System Strength Locational Factors and Corresponding Nodes

As per Schedule 5.8 (q) of the NER, AusNet is required to include in this report the system strength locational factor (SSLF) for each system strength connection point for which it is the Network Service Provider and the corresponding system strength node. The SSLFs and corresponding nodes are provided in Appendix F and can be found on our Subtransmission Ratings and Connections Dashboard.

5. Network Asset Retirements and De-ratings

This section, coupled with Section 9, addresses the requirements for reporting of network asset retirements and deratings as described in Schedule 5.8 (b1) and (b2) of the NER. The information is presented in two categories: Individual assets and Grouped assets.

The assets categories reflect the relative size or significance of the asset and the approach to management of asset retirement and replacement. Items listed in the individual asset category are usually the subject of a proactive planned retirement process. These assets are typically retired and, where proven to be economically feasible replaced. Items listed in the grouped asset category are usually retired and replaced as part of a program of work in response to inspection programs throughout the network.

The assets assigned to the individual and grouped asset categories are listed in Appendix C.

5.1. Individual asset retirement and de-ratings

Referring to AMS 01-09, asset retirements is a major component of asset risk management. The prerequisites for retirement or derating of assets:

- replacement or derating of an asset will result in a material risk reduction
- risks can't be feasibly managed through maintenance or refurbishment
- monetised risk exceeds the replacement cost – ie replacement is economic.

Where AusNet is planning or has committed to retire and, where economically justified, replace individual assets, these works are summarised in Section 9.

In 2018, AusNet reviewed and revised its zone substation transformer cyclic ratings. The ratings are reflected in the firm capacity MVA ratings, presented in the tables of Section 4.6.3, and the network limitations identified in Section 6.2. The cyclic ratings are based on daily load curves for each zone substation and are prepared in line with

Australian Standard AS 2374.7 – 1997 Loading Guide for Power Transformers, as outlined in AusNet asset management strategy AMS 20-101.

5.2. Grouped asset retirement and de-ratings

Summaries of asset retirement and de-ratings of Grouped assets is contained in the Appendix. The asset statement for each Group provides an overview of the methodologies and assumptions used in the development of the asset management strategies that influence the retirement or de-rating of the asset group. The complete asset management strategies are available upon request to the contact outlined in the Disclaimer at the beginning this report. The complete asset management strategies were provided to the Australian Energy Regulator as part of the Electricity Distribution Price Reset submission.

6. System Limitations for Sub-Transmission Lines and Zone Substations

This section provides details required by schedule 5.8 (c) of the NER covering information on system limitations for sub-transmission lines and zone substations. The assessments and information on the limitations cover what is required in (1) to (5) and include:

- Estimates of the location and timing of the system limitations.
- Analysis of any potential load transfer capacity between supply points that may decrease the impact of the system limitation or defer the requirement for investment.
- A brief discussion of the types of potential solutions that may address the system limitation in the forward planning period.

Where an estimated reduction in forecast load or generation would defer a forecast system limitation for a period of at least twelve months, the following has been provided:

- An estimate of the month and year in which a system limitation is forecast to occur.
- The relevant connection points at which the estimated load or generation reduction may occur.
- The estimated reduction in forecast load or generation (MW), or improvements in power factor needed to defer the forecast system limitation.

None of the system limitations identified in Section 6 have an impact on the capacity at transmission-distribution connection points.

6.1. Sub-transmission line import limitations

This section discusses identified sub-transmission line import limitations. It assesses the limitation, its impact and, where possible, suggests potential solutions. Some minor limitations that exist under contingency conditions, but where there is sufficient load transfer capability to supply the load, are not discussed in detail in this section, but are reported in the tables of Section 4.6.2.

6.1.1. CBTS-LYD-NRN-PHM-OFR-BWN-LLG-CLN-CBTS 66 kV loop

The Cranbourne Terminal Station (CBTS) to Lysterfield (LYD) to Narre Warren (NRN) to Pakenham (PHM) to Officer (OFR) to Berwick North (BWN) to Lang Lang (LLG) to Clyde North (CLN) 66 kV loop supplies over 114,000 customers via the seven zone substations listed. This 66 kV loop has energy at risk over the summer period from December to March. The worst-case outage is the loss of the CBTS-LYD 66 kV line where loading on the CBTS-BWN 66 kV line will exceed its rating at maximum demand. The firm capacity of this loop is 243 MVA. The summer 2024/25 forecast total peak non coincident 66 kV loop maximum demand is 330MVA increasing to 390 MVA in summer 2028/29, under PoE10 conditions.

The level of overload exceeds the load transfer capacity to zone substations supplied from other adjacent 66 kV loops, and AusNet is investigating options to mitigate the network limitation and identified supply risk. Figure 7 shows the single line diagram of this loop along with the constrained line segments (coloured in red) under various single order contingency events in this loop.

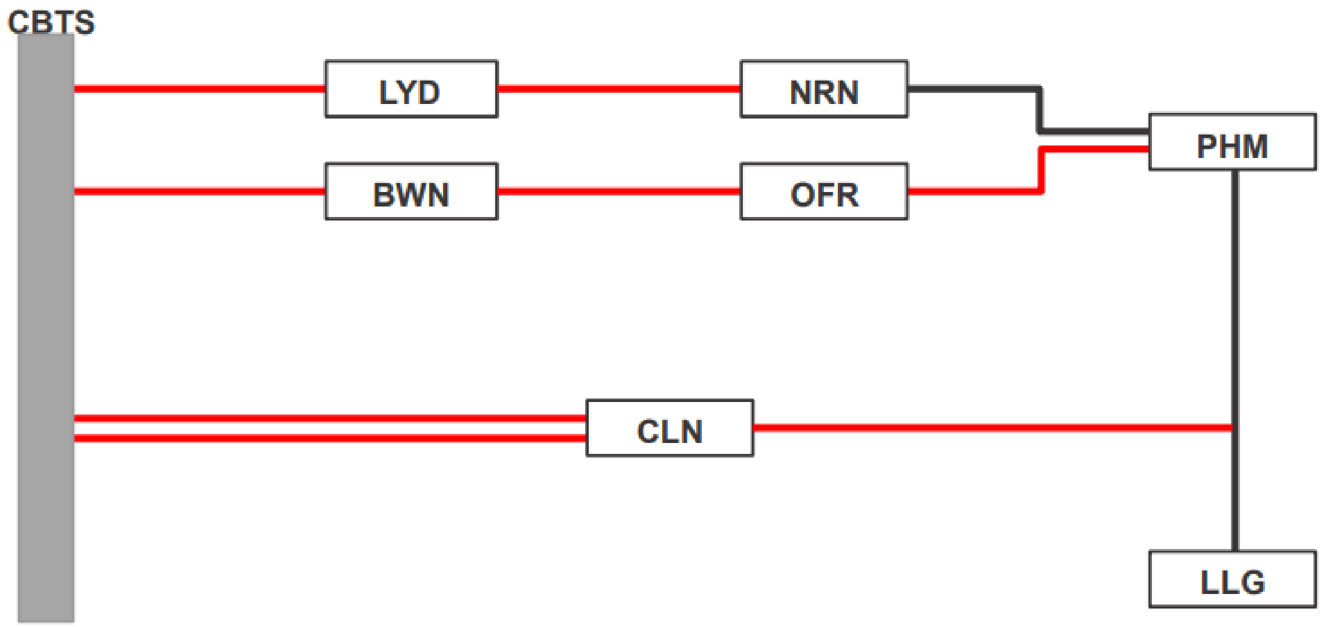


Figure 7: CBTS-LYD-NRN-PHM-OFR-BWN-LLG-CLN 66 kV Loop

A contingency plan has been developed to transfer load away via 22 kV links to the adjacent zone substations in the event of a line outage.

AusNet has also established an option to extend the 66 kV network to allow Lysterfield Zone Substation (LYD) and

Narre Warren Zone Substation (NRN) to be supplied radially from East Rowville Terminal Station (ERTS), and BWN and OFR to be supplied radially from ERTS, thereby offloading this CBTS 66 kV loop, during network contingency events. While this contingency plan supports network supply capacity under contingency events, it requires LYD and NRN, as well as BWN and OFR to be supplied radially from ERTS, thereby significantly increasing the network supply risk for subsequent outages.

Longer term options being considered to mitigate the identified supply risk, include:

- Establish a new CBTS-PHM 66kV line.
- Establish a new CBTS-OFR 66kV line.
- Establish a third CBTS-CLN 66 kV line and a second CLN-LLG 66 kV line.
- Establish a second PHM-LLG 66 kV line.
- Re-conductor the existing CBTS-LYD 66 kV line.
- Generators or other network support measures.

These, and any other, potential supply risk mitigation options will be subject to the outcome of a future RIT-D assessment.

6.1.2. LGA-WGI-PHI 66 kV loop

The Leongatha (LGA) to Wonthaggi (WGI) loop and radial 66 kV line to Phillip Island (PHI) supplies over 33,600 customers via the two zone substations at Wonthaggi and Phillip Island. This LGA – WGI 66 kV loop has energy at risk over the peak tourism seasons including school holidays, long weekends and special events such as the Motorcycle Grand Prix. An outage of either the LGA – LSSS, LSSS - WGI or LGA - LSSS/WGI 66 kV lines will result in voltage collapse of this network and loss of supply at both zone substations if loading exceeds 56.0 MVA, and load shedding if the thermal loading exceeds 32.0 MVA.

Maximum non-coincident demand occurs in summer and is expected to reach 76.7 MVA in summer 2024/25, increasing to 81.7 MVA in summer 2028/29 under PoE10 conditions. The BHWF output also reduces risk in this part of the network. Figure 8 shows the single line diagram of this loop along with the constrained line segment (coloured in red) under single order contingency.

In late-2020, AusNet published a request for proposals (RFP) to enter into a 4.95 MW / 10 MWh network support contract in the PHI area. The selected service provider, the Phillip Island Community Energy Storage System (PICESS), is now installed on the network and will provide network support when requested.

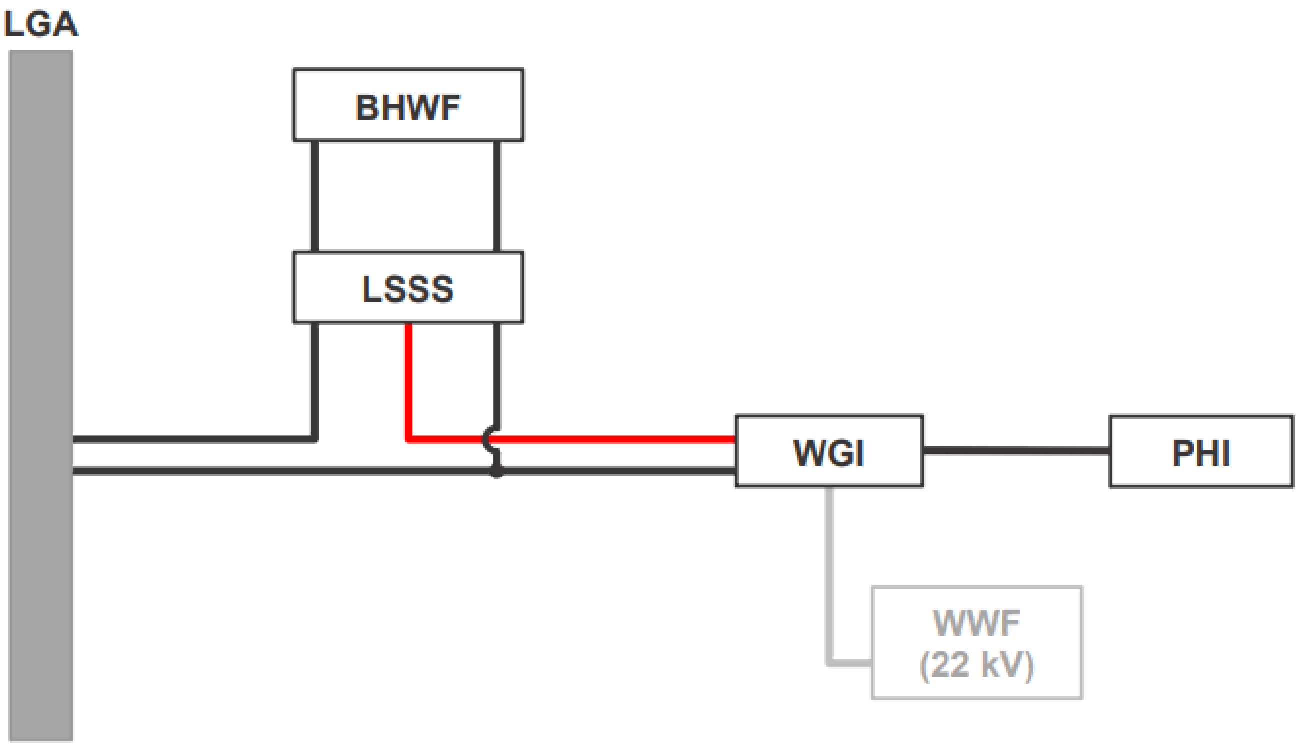


Figure 8: LGA-WGI-PHI 66 kV Loop

Other options considered by AusNet included:

- Re-conductor up to 27 kilometres of existing 6/1/.186 ACSR conductor to 19/4.75 AAC conductor in the LSSS – WGI and LGA – LSSS/WGI 66 kV lines.
- Contract network support via embedded generation connected to WGI or PHI to reduce demand during risk periods.
- Contract for network support via demand management to reduce demand during risk periods.

Additionally, a contingency plan has been developed to transfer load away via 22 kV links to the adjacent zone substations in the event of a line outage.

6.1.3. MWTS-LGA-FTR-WGI-PHI 66 kV loop

The Morwell Terminal Station (MWTS) to Leongatha (LGA) to Foster (FTR) to Wonthaggi (WGI) to Phillip Island (PHI) 66 kV network supplies over 54,900 customers via the four zone substations at Leongatha, Foster, Wonthaggi and Phillip Island. This 66 kV loop has energy at risk over the peak tourism season of Christmas and early January. An outage of either of the MWTS-LGA No. 1 or the No. 3 66 kV line will result in thermal overload of the MWTS-LGA No. 2 66 kV line, requiring load shedding if loading exceeds 92.3 MVA. Maximum non coincident demand under single contingency outage in summer is expected to reach 136.5 MVA in summer 2024/25 increasing to 144.1 MVA in summer 2028/29 under PoE10 conditions. The 106 MW Bald Hills Wind Farm (BHWF), connected into this 66 kV loop in 2015, generates sufficient output to eliminate the risk of overload under single contingency, and for most of the time. The Wonthaggi Wind Farm (WWF) also serves to mitigate this energy-at-risk when it is operating.

As mentioned in section 6.1.2, we have contracted a Non-Network solution (PICESS) that will also help to reduce the load at risk on this loop.

Figure 9 shows the single line diagram of this loop along with the constrained line segment (coloured in red) under single order contingency.

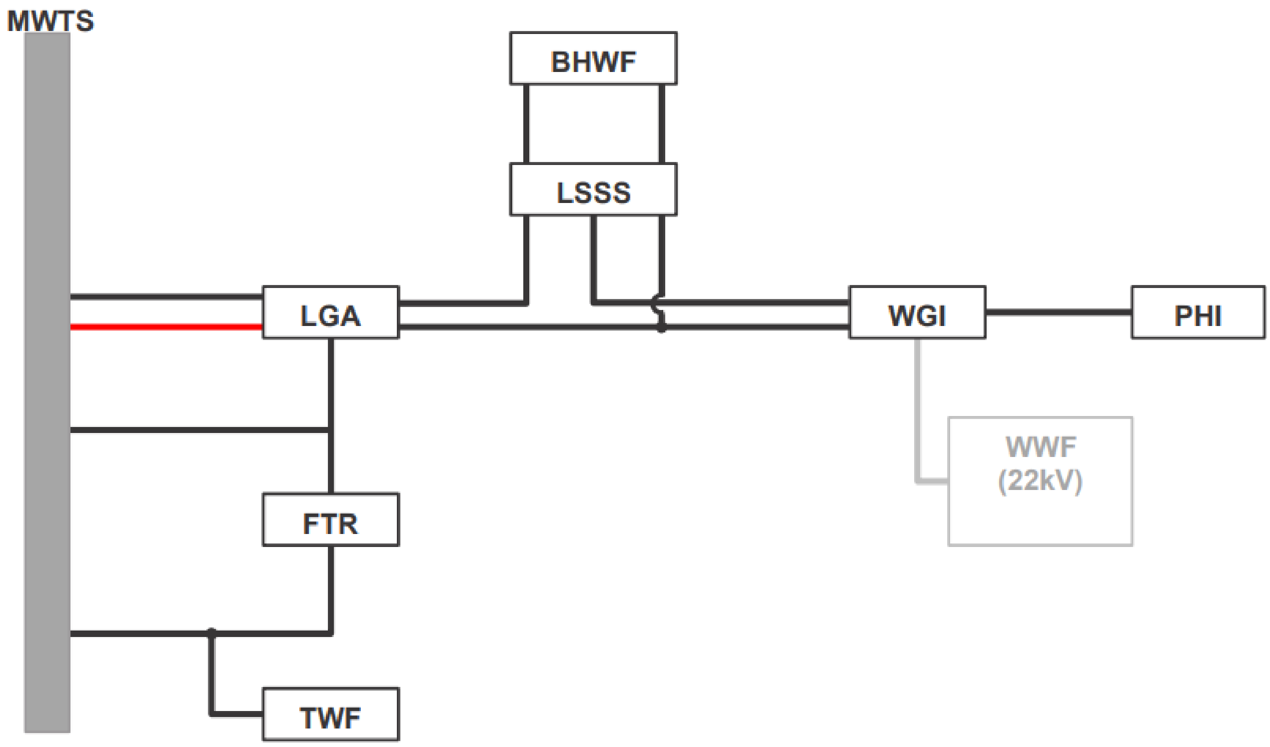


Figure 9: MWTS-LGA-FTR-WGI-PHI 66 kV Loop

AusNet has been examining options to address this summer constraint and the following are being considered:

- Re-conductor up to 22 kilometres of existing 6/1/.186 ACSR conductor to 19/4.75 AAC conductor in the MWTS-LGA No. 2 66 kV line.
- Contract network support via embedded generation connected to LGA, WGI or PHI, to offset demand during risk periods.
- Contract for network support via demand management, to reduce demand during supply risk periods.

A contingency plan has been developed to transfer load away via 22 kV links to the adjacent zone substations in the event of a line outage.

As mentioned in Section 8.1.7 AusNet has also recently published a RIT-D in which the preferred option involves the upgrade of the MWTS-LGA No.2 and No.3 66 kV lines to 37/3.75 AAC conductor. Should this project proceed, the summer constraint described above will be significantly reduced.

6.1.4. MWTS-TGN-SLE-MFA-BDSS-BDL-NLA-CNR 66 kV loop

The East Gippsland 66 kV network, which emanates from Morwell Terminal Station (MWTS), supplies over 71,400 customers via six AusNet zone substations, including Traralgon (TGN), Sale (SLE), Maffra (MFA), Bairnsdale (BDL), Newmerella (NLA) and Cann River (CNR). This loop experiences thermal overloading when the loop load exceeds

171 MVA. Further, this loop is exposed to voltage collapse situations during N-1 conditions if the loop load exceeds

105 MVA. Between the years 2000 and 2020 the network security risks were mitigated by requesting Bairnsdale Power Station (BPS) to generate under a Network Support Agreement (NSA). Although, this NSA is no longer in force, past data shows that BPS is generates nearly 80 MW during most of the peak loading periods as a merchant generator. This helps to maintain the network security. Moreover, it is expected that with proper outage management in combination with appropriate load shedding schemes, the security of the network can be maintained. Maximum non coincident demand in the East Gippsland loop in is expected to reach 196.8 MVA in summer 2024/25 increasing to 210.5 MVA in summer 2028/29 under PoE10 conditions.

In September 2020, AusNet published a non-network options report outlining the risks on this 66 kV network. Submissions to this non-network options report closed on 8 January 2021. After a review of the submissions, AusNet final decision was to close the RIT-D and continue to monitor peak demand growth on the East Gippsland 66 kV network as increases in new renewable energy generation connections continue. If deemed necessary, this project will undergo a reassessment through the RIT-D process.

Figure 10 shows the single line diagram of this loop along with the constrained line segments (coloured in red) under single order contingency.

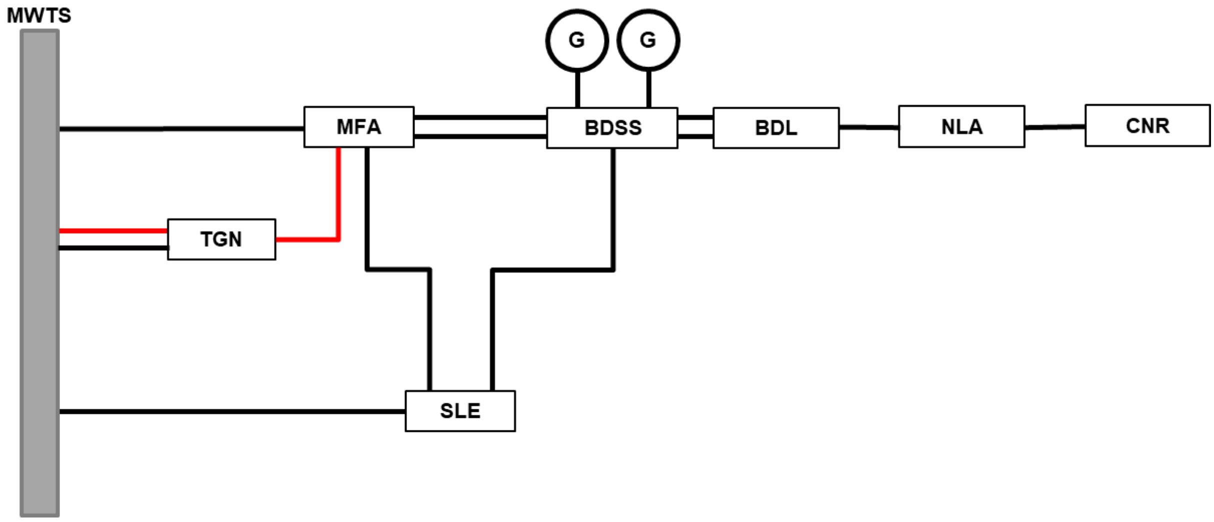


Figure 10: MWTS-TGN-SLE-BDSS-BDL-NLA-CNR 66 kV Loop

6.1.5. SMTS-DRN-KLK-MDI-RubA-YEA-SMR-KMS 66 kV loop

The Doreen (DRN) to Kinglake (KLK) to Rubicon A (RubA) to Seymour (SMR) to Kilmore South (KMS) 66 kV loop supplies approximately 19,200 customers via the four zone substations at Kinglake, Rubicon A, Murrindindi, and Seymour. The supplies to KLO, KMS and DRN are secured by duplicated 66 kV lines, but the sections beyond these stations are at risk. This 66 kV loop has energy at risk over the summer period from December to March inclusive as well as the winter period from June to August inclusive. An outage of the KMS-SMR or the DRN-KLK 66 kV lines can result in voltage collapse of the network and loss of these four zone substations. No other line outage is expected to result in loss of customer load in 2024/25. Figure 11 shows the single line diagram of this loop along with the constrained line segments under single order contingency. It also shows the new KLO-DRN 66 kV line, which was commissioned in July 2018.

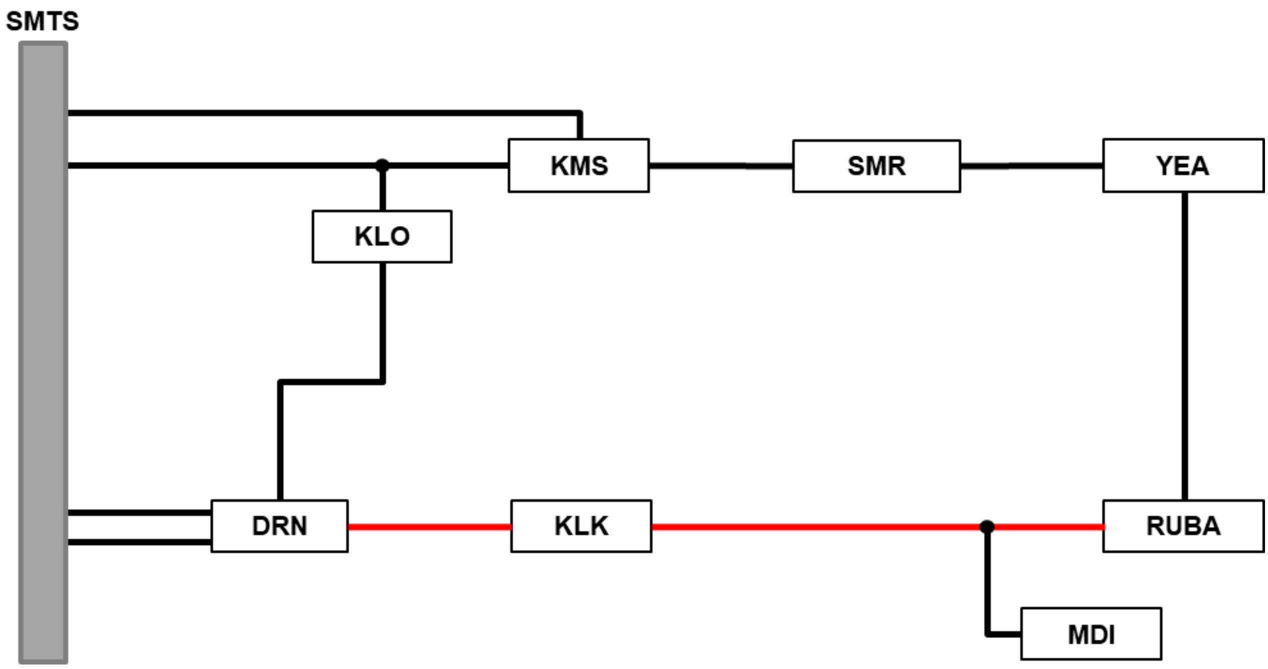


Figure 11: SMTS-DRN-KLK-MDI-RUBA-YEA-SMR-KMS 66 kV Loop

AusNet has been examining options to address the potential voltage collapse constraint, and the following have been considered:

- Construct new KMS-SMR No. 2 66 kV line. This option is expected to cost in excess of $30 million and is not currently considered economically feasible.

- Contract network support via embedded generation connected at Seymour, to reduce network loading during risk periods.
- Contract for network support via demand management, to reduce demand during risk periods.

It is not expected that any work will be implemented in the next five years as they are not yet economic considering the probabilistic planning approach. A contingency plan has been developed to transfer load away via 22 kV links to the adjacent zone substations in the event of a line outage.

6.1.6. TTS-WT-NEL-NH 66 kV loop

The Thomastown Terminal Station (TTS) to Watsonia (WT) to North Heidelberg (NH) to TTS 66 kV loop supplies approximately 45,000 customers (including around 25,000 AusNet customers) via the two zone substations at Watsonia and North Heidelberg. The NEL and NH zone substation is owned by Jemena. The NEL ZSS is for North East link for tunnel boring. The NH 66 kV loop has energy at risk over the summer period from December to March inclusive. Both the TTS-WT (line owned by AusNet) and TTS-NH (line owned by Jemena) 66 kV lines have a rating of 1,025 amps (117.2 MVA) in summer. The maximum coincident demand is forecast to reach 126.7 MVA in summer 2024/25, growing slowly to 133.5 MVA by summer 2028/29 under PoE10 conditions. Figure 12 shows the single line diagram of this loop along with the constrained line segments (coloured in red) under single order contingency.

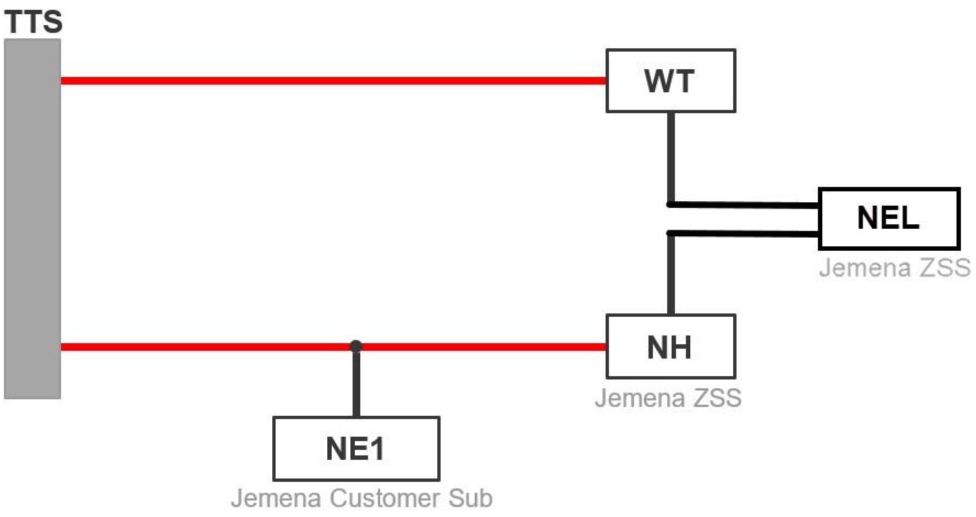


Figure 12: TTS-WT-NEL-NH 66 kV Loop

A contingency plan has been developed to transfer load away via 22 kV links to the adjacent zone substations including Jemena zone substations.

6.1.6. MWTS-YPS-MOE-WGL-MWTS

The Morwell Terminal Station (MWTS) to Yallourn Power Station (YPS) to Moe (MOE) to Warragul (WGL) 66 kV loop supplies approximately 42,370 customers. This 66 kV loop has energy at risk over the summer period from December to March. The worst-case outage is the loss of the YPS-WGL No.1 66 kV line where loading on the YPS-WGL/MOE 66 kV line between YPS and the tee point will exceed its rating at maximum demand. Figure 13 shows the single line diagram of this loop, and the single order contingency constrained line segment (coloured in red).

From a thermal capacity perspective, the loop should not be loaded above its secure system normal planning limit of 117 MVA in summer and 151 MVA in winter. Exceeding these limits leads to dangerous overloading of the 66kV lines beyond their normal capacity. Due to conductor thermal inertia characteristics, loading 66 kV lines at their normal rating does not allow network controllers sufficient time to reduce load to within asset ratings and can, therefore, result in irreversible conductor damage, cascade tripping of network elements and safety risks if the lines touch the ground due to sagging. From 2026 onwards, the secure system normal planning limit of 117 MVA in summer of the West Gippsland 66kV loop is expected to be exceeded.

Additionally, the supply to the West Gippsland region is limited under network outage conditions by the thermal capacity of key 66 kV lines. Without manual switching by System Operations, there would be significant values of load at risk (L@R) today on YPS-MOTEE2, MOTEE2-WGL, MOTEE1-MOE and MWTS-MOE lines under single contingency event (N-1).

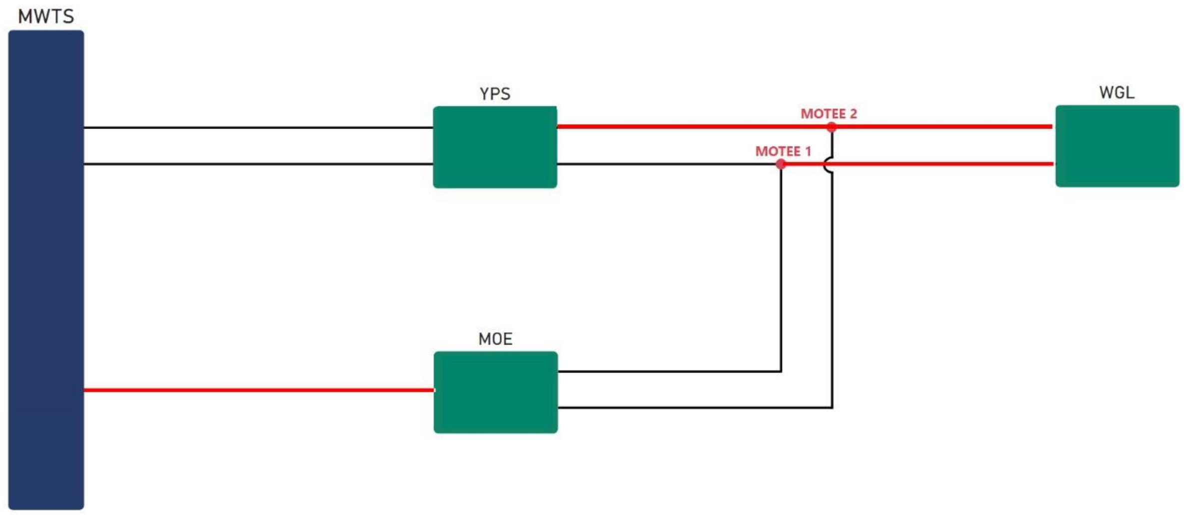


Figure 13: MWTS-YPS-MOE-WGL 66 kV Loop

AusNet is currently examining options to address the thermal constraint in case of higher-than-expected POE 10 load forecasts as experienced in previous years. Options being examined are:

- Reconductor the constrained 66kV lines.
- Contract network support via embedded generation connected to WGL or MOE, to offset demand during risk periods.
- Contract for network support via demand management, to reduce demand during supply risk periods.

6.1.7. Radial 66 kV lines

AusNet has ten zone substations, including Barnawartha (BWA), Cann River (CNR), Clover Flat (CF), Lang Lang (LLG), Mansfield (MSD), Merrijig (MJG), Mount Beauty (MBY), Newmerella (NLA), Phillip Island (PHI) and Rowville (RVE), which are supplied via single radial 66 kV lines. All of these lines have sufficient capacity over the next five years to supply the forecast demand, however all customers supplied from these zone substations face outages whenever the 66 kV supply line has an outage. Reinforcing these radial 66 kV networks with the construction of a second 66 kV line depends on the reliability performance of the existing radial 66 kV line, and the resultant expected unserved energy. In each of the ten cases, AusNet planning criteria shows that it is not currently economic to duplicate the 66 kV line. While 66 kV line duplication is not economic, AusNet is open to network support and other innovative options to mitigate the supply risks.

To support the NLA and CNR radial 66 kV network, AusNet has installed a battery energy storage system known as the Mallacoota Area Grid Storage (MAGS). The heart of MAGS is a lithium-ion battery system with a total storage capacity of 1 MW / 1 MWh. The MAGS battery is charged from the grid and will feed power back into the grid during local outages, in parallel with its 1 MW diesel generator. The facility is located at the East Gippsland Water treatment plant, just outside the Mallacoota township.

6.2. Zone substations import limitations

This section discusses identified zone substation import limitations. It assesses the limitation, its impact and, where possible, suggests potential solutions. Some minor limitations that exist under contingency conditions, but where there is sufficient load transfer capability to supply the load, are not discussed in detail in this section, but are reported in the tables of Section 4.6.3.

This section presents the zone substations that are carrying, or are forecast to carry, significant service level risk under N-1 in the five-year forward planning period. This service level risk is also quantified alongside commentary outlining the primary drivers of the identified risk.

In some cases, the load transfer capacity is sufficient to cover the N-1 supply risk. However, the service level risk and supply risk cost also consider and quantifies other risk factors such as safety, collateral damage and reactive replacement costs.

Where AusNet considers it economic to do so, network development plans are outlined in Section 9 of this DAPR.

6.2.1. Benalla Zone Substation (BN)

Benalla (BN) is located approximately 212 km north-east of Melbourne and is the main source of supply for the rural towns of Benalla, Euroa, Lima South, Tatong, and Goorambat townships. BN supplies approximately 12,500 AusNet customers. The customer base supplied from BN is predominately made up of residential (66%) and farming (24%), with some commercial and industrial.

BN is a summer peaking station, and the peak electrical demand reached 31.1MVA in summer 2023/24, and is forecast to grow to 43.1MVA by 2028/29. The load transfer capability of the feeder interconnections between BN and its neighbouring zone substations is approximately 2.6 MVA.

Table 9 shows the estimated magnitude of load at risk, annual hours at risk and the magnitude expected unserved energy (EUSE).

Table 9: Expected 10% POE energy at risk at BN Zone Substation.

BN	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	33.5	33.9	34.3	34.7	35.2
10% POE Max Overload (%)	9.1	10.4	11.7	13.2	14.7
EUSE (MWh)	5.0	6.6	8.7	12.1	17.0
Hours at Risk (h)	4.1	4.8	6.6	9.8	13.1

A summary of the 5 -scale Likelihood of Failure score of key assets at BN Zone Substation is provided in Figure 14 below.

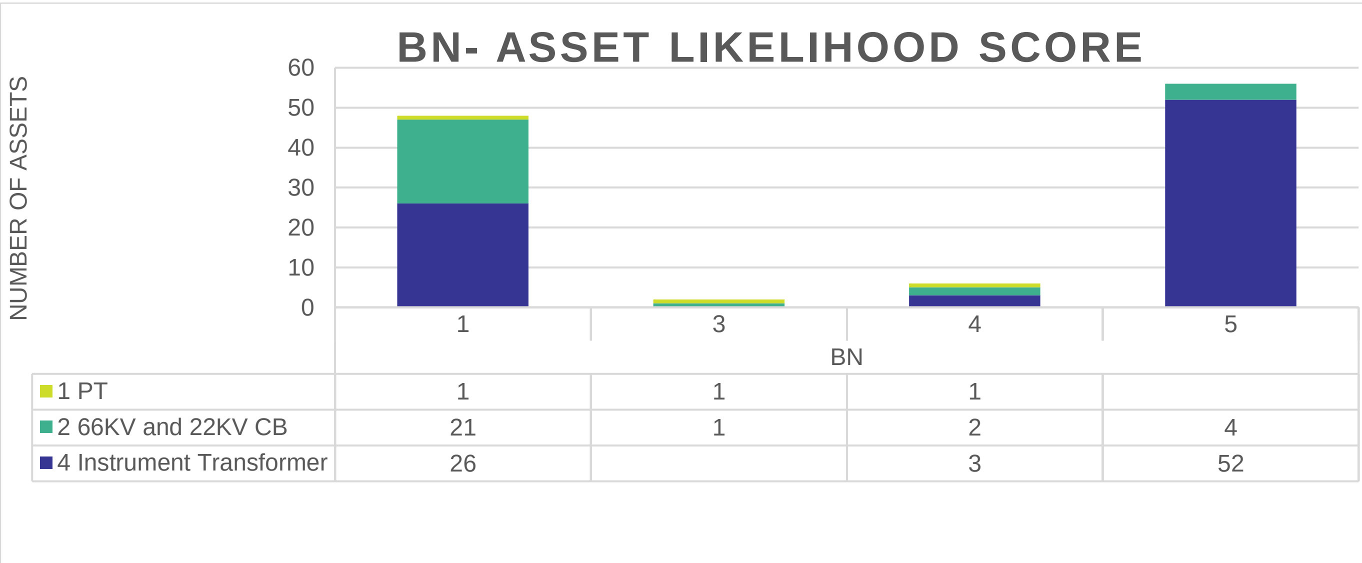


Figure 14: Number of Assets by Likelihood Score at BN Zone substation.

The service level risk to customers supplied from BN Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis and ARM data modelling identified the preferred option as replacing both the 66kV and 22kV circuit breakers by 2024. The 22kV switchgear has been replaced as part of REFCL augmentation and A project has commenced to replace these 66kV breakers.

6.2.1. Bayswater Zone Substation (BWR)

Bayswater (BWR) is located in the eastern suburbs of metropolitan Melbourne, approximately 29km east of Melbourne and is the main source of supply for the suburbs of Bayswater, Croydon South, Kilsyth South, Wantirna and

Heathmont. BWR supplies approximately 19,953 AusNet customers. The load at BWR includes mostly residential combined with commercial loads and with some industrial loads.

BWR is a summer peaking station, and the peak electrical demand reached 52.5MVA in the summer of 2023/24. This station does not have any load at risk driven by the increase in demand in the upcoming period.

A summary of the 5 -scale Likelihood of Failure score of key assets at BWR Zone Substation is provided in Figure 15 below.

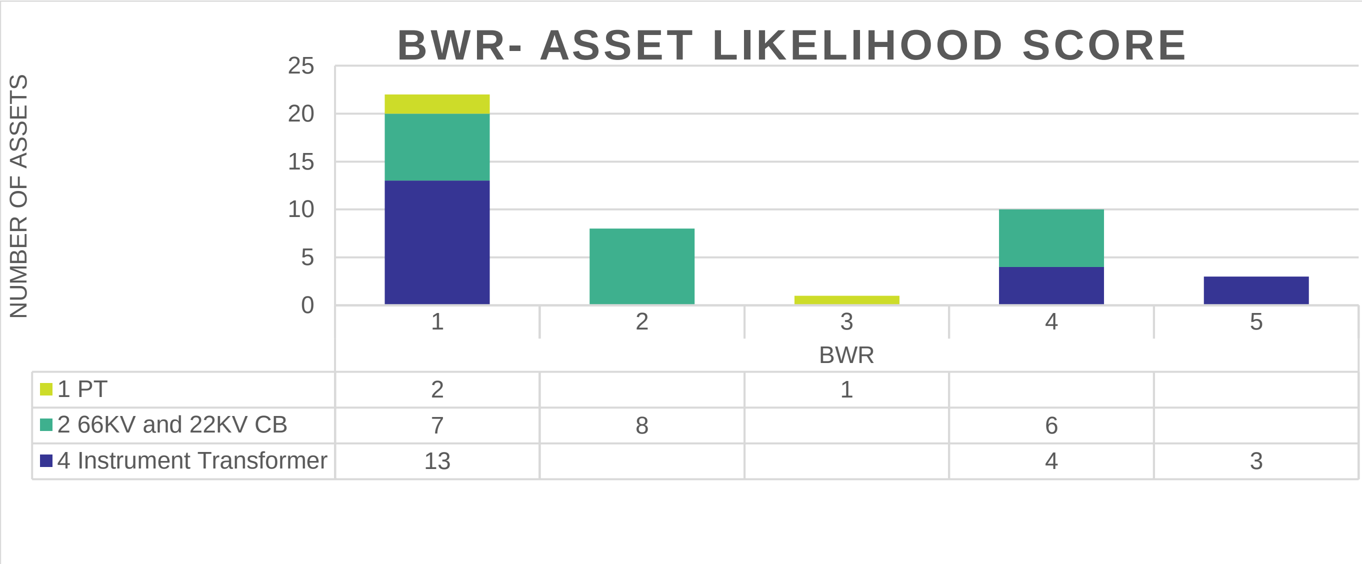


Figure 15: Number of Assets by Likelihood Score at BWR Zone substation.

The service level risk to customers supplied by BWR is forecast to grow to unacceptable levels. Consequently, the options analysis and ARM data modelling identified the preferred option as replacing the 22kV switchgear by Q1 of 2026.

6.2.2. Clyde North Zone Substation (CLN) – need to recalculate for new Tx

Clyde North (CLN) Zone Substation consists of two 66/22 kV 20/33 MVA transformers supplying two 22 kV buses and seven 22 kV feeder circuits. The substation supplies approximately 46,599, mostly residential and commercial, in Victoria's southeast growth corridor.

CLN Zone Substation is a summer peaking station, and the peak electrical demand reached 84.4MVA in the summer of 2023/24. Table 10 shows the estimated magnitude of load at risk, annual hours at risk and the magnitude expected unserved energy (EUSE). These calculations assume that another 33MVA transformer will be installed in 2025.

Table 10: Expected 10% POE energy at risk at CLN Zone Substation.

CLN	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	73.0	80.4	88.2	96.0	104.1
10% POE Max Overload (%)	67.8	84.7	102.8	120.7	139.3
EUSE (MWh)	0.0	1.4	35.5	128.1	287.4
Hours at Risk (h)	0.0	0.8	8.7	18.4	29.8

To address the load and energy at risk at CLN, an augmentation project has been initiated in the current regulatory reset period. The augmentation works include establishing a new 66/22 kV transformer, a 66 kV circuit breaker to facilitate connection of the new transformer, and a new 22 kV switchboard to facilitate connection of the new transformer. These works will be followed by the installation of a new 22kV distribution feeder required to offload other 22kV feeders in the area.

A summary of the 5 -scale Likelihood of Failure score of key assets at CLN Zone Substation is provided in Figure 16 below.

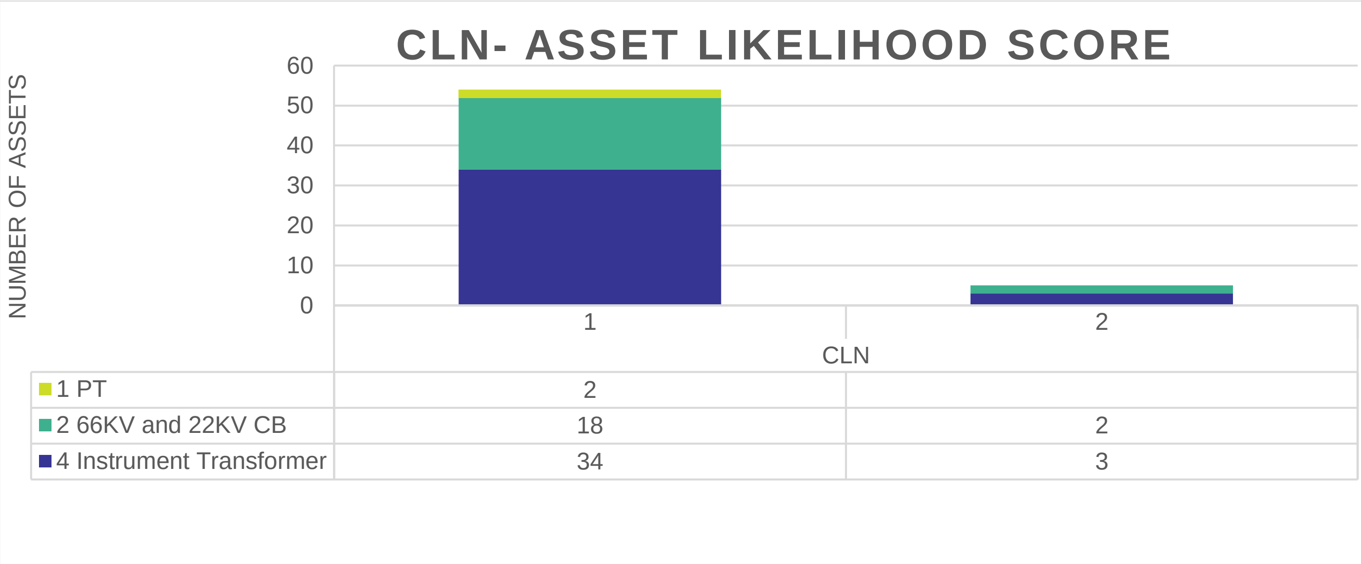


Figure 16: Number of Assets by Likelihood Score at CLN Zone substation

6.2.3. Doreen Zone Substation (DRN)

Doreen (DRN) zone substation consists of two 66/22 kV 20/33 MVA transformers supplying two 22 kV buses and eight 22 kV feeder circuits. The substation supplies approximately 32,788 mostly residential customers in Victoria's northern growth corridor.

DRN Zone Substation is a summer peaking station, and the peak demand reached 60.7 MVA in the summer of 2023/24. Table 11 shows the estimated magnitude of load at risk, annual hours at risk and the magnitude expected unserved energy (EUSE).

Table 11: Expected 10% POE energy at risk at DRN Zone Substation.

DRN	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	46.6	47.9	49.3	50.7	52.4
10% POE Max Overload (%)	1.5	4.3	7.3	10.5	14.1
EUSE (MWh)	0.2	1.7	4.4	11.3	23.5
Hours at Risk (h)	0.6	1.3	3.4	6.5	9.6

A summary of the 5 -scale Likelihood of Failure score of key assets at DRN Zone Substation is provided in Figure 17 below.

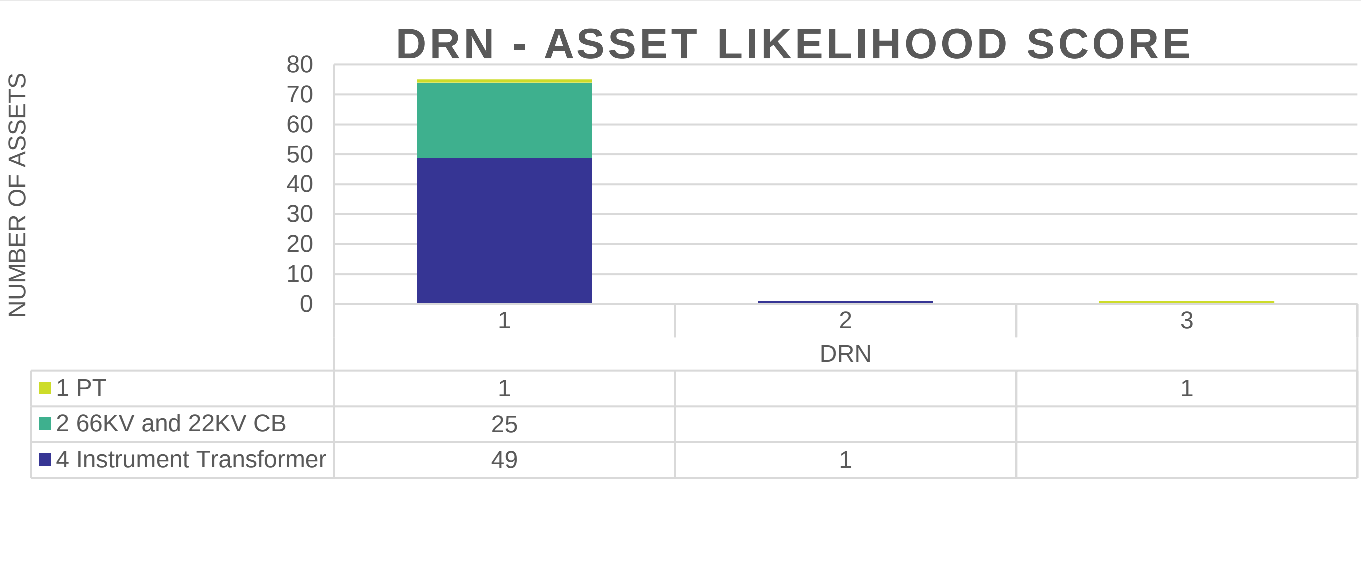


Figure 17: Number of Assets by Likelihood Score at DRN Zone substation.

6.2.4. Epping Zone Substation (EPG)

Epping (EPG) zone substation consists of three 66/22 kV 20/33 MVA transformers supplying three 22 kV buses and thirteen 22 kV feeder circuits. The substation supplies approximately 30,495 mostly residential customers in Melbourne's northern suburbs.

EPG Zone Substation is a summer peaking station, and the peak demand reached 90.1 MVA in the summer of 2023/24. The load transfer capability of the feeder interconnections between EPG and its neighbouring zone substations is approximately 12.2 MVA. Table 12 shows the estimated magnitude of load at risk, annual hours at risk and the magnitude expected unserved energy (EUSE).

Table 12: Expected 10% POE energy at risk at EPG Zone Substation.

EPG	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	84.3	89.7	95.1	100.5	106.0
10% POE Max Overload (%)	2.8	9.4	15.9	22.6	29.3
EUSE (MWh)	0.1	11.0	57.3	164.9	326.9
Hours at Risk (h)	0.3	4.4	16.1	28.0	40.7

6.2.5. Kalkallo Zone Substation (KLO)

The KLO is a zone substation established in 2010 and supplies Kalkallo, Wallan, Woodstock and Wandong. Currently it has two 20/33 MVA transformers and two 22kV feeders with outdoor 66kV and indoor 22kV switchgear in a switched configuration.

KLO is a summer peaking station, and the peak demand reached 47.2MVA in the summer of 2023/24. Table 13 shows the estimated magnitude of load at risk, annual hours at risk and the expected unserved energy (EUSE).

Table 13: Expected 10% POE energy at risk at KLO Zone Substation

KLO	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	61.7	75.0	91.2	106.4	121.8
10% POE Max Overload (%)	25.7	52.7	85.8	116.8	148.0

EUSE (MWh)	1105.2	7090.2	21422.1	42224.6	69220.4
Hours at Risk (h)	286.7	824.0	1672.1	2603.9	3285.5

A summary of the 5 -scale Likelihood of Failure score of key assets at DRN Zone Substation is provided in Figure 18 below.

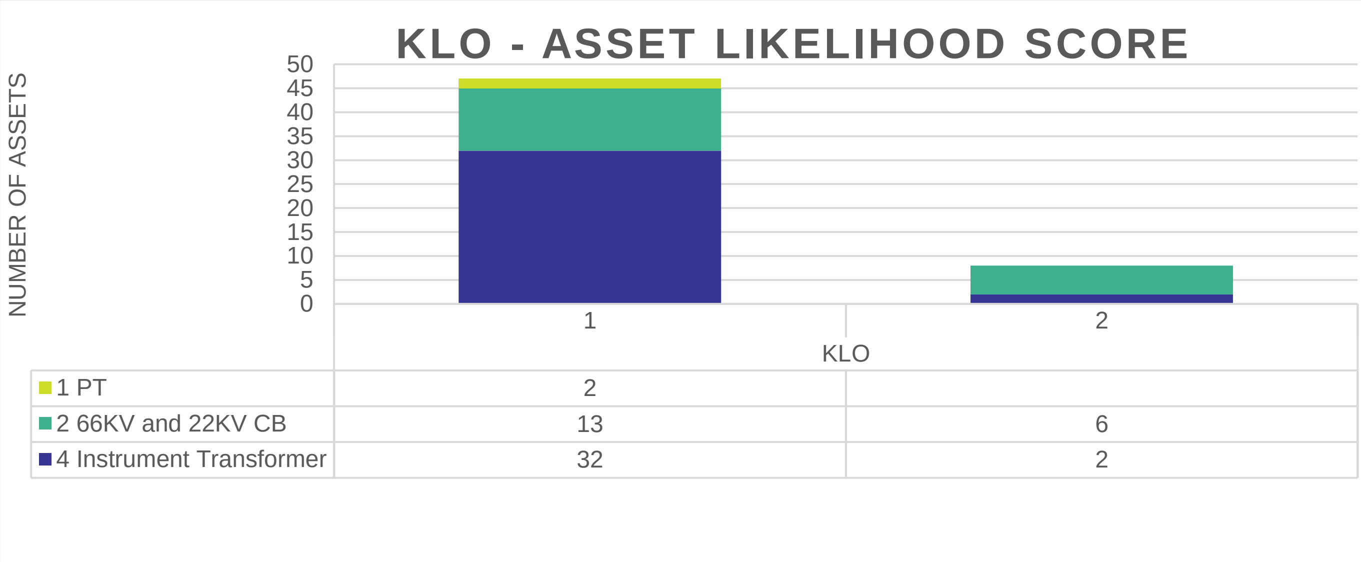


Figure 18: Number of Assets by Likelihood Score at KLO Zone substation.

6.2.6. Lang Lang Zone Substation (LLG)

Land Lang (LLG) zone substation consists of one 66/22 kV 20/33 MVA transformer supplying one 22 kV bus and four 22 kV feeder circuits. The substation supplies approximately 7,251 mostly residential customers.

EPG Zone Substation is a summer peaking station, and the peak demand reached 21.3 MVA in the summer of 2023/24. The demand at LLG is forecast to increase to 22 MVA by 2029. Table 14 shows the estimated magnitude of load at risk, annual hours at risk and the magnitude expected unserved energy (EUSE).

Table 14: Expected 10% POE energy at risk at LLG Zone Substation.

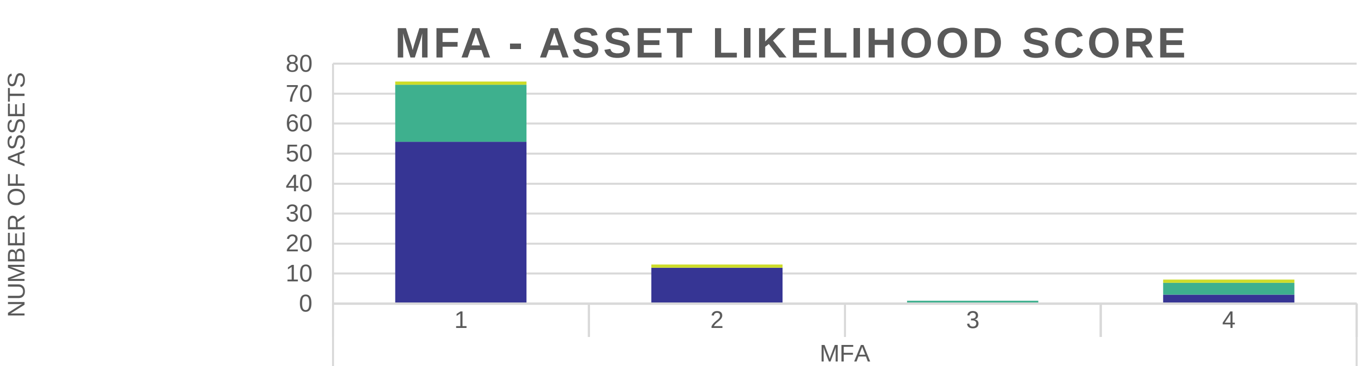
LLG	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	1.7	3.9	5.3	6.2	7.0
10% POE Max Overload (%)					
EUSE (MWh)	3842.5	8767.7	11918.0	14013.9	15775.9
Hours at Risk (h)	4391.1	4391.1	4391.1	4391.1	4391.1

6.2.7. Maffra Zone Substation (MFA)

Maffra (MFA) is located approximately 220km east of Melbourne supplying approximately 8,700 customers. The load at MFA includes town and rural based residential, with some town based commercial, industrial and farming.

MFA is a summer peaking station and the peak electrical demand reached 30.7 MVA in the summer of 2022/23. The demand at MFA is forecast to increase to 35.2 MVA by 2027/28. The load transfer capability of the feeder interconnections between MFA and its neighbouring zone substations is approximately 6.5 MVA. This station does not have any load at risk driven by the increase in demand in the upcoming period.

A summary of the 5 -scale Likelihood of Failure score of key assets at DRN Zone Substation is provided in Figure 19 below.



	1	2	3	4
1 PT	1	1		1
2 66KV and 22KV CB	19		1	4
4 Instrument Transformer	54	12		3

Figure 19: Number of Assets by Likelihood Score at MFA Zone substation.

The service level risk to customers supplied from MFA Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis and ARM data modelling identified the preferred option as replacing the 66kV circuit breakers by 2024.

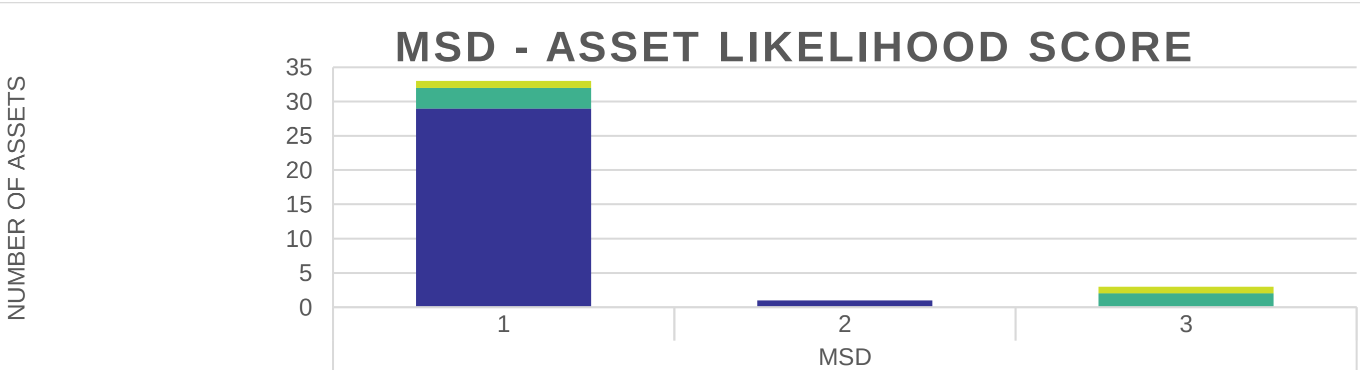
6.2.8. Mansfield Zone Substation (MSD)

Mansfield (MSD) zone substation consists of two 66/22 kV 10/13 MVA transformers supplying two 22 kV buses and three 22 kV feeder circuits. The substation supplies approximately 6,830 residential, commercial, industrial, and agricultural customers north-east of Melbourne.

MSD is a summer peaking station and the peak electrical demand reached 15.7 MVA in the summer of 2022/23. The demand at MSD is forecast to increase to 21.3 MVA by 2027/28. The load transfer capability of the feeder interconnections between MSD and its neighbouring zone substations is approximately 5 MVA.

This station does not have any load at risk driven by the increase in demand in the upcoming period.

A summary of the 5 -scale Likelihood of Failure score of key assets at DRN Zone Substation is provided in Figure 20 below.



	1	2	3
1 PT	1		1
2 66KV and 22KV CB	3		2
4 Instrument Transformer	29	1	

Figure 20: Number of Assets by Likelihood Score at KLO Zone substation.

6.2.8. Myrtleford Zone Substation (MYT)

Myrtleford (MYT) zone substation consists of two 66/22 kV 10/13.5 MVA transformers supplying two 22 kV buses and four 22 kV feeder circuits. The substation supplies approximately 6,100 residential, commercial, industrial, and agricultural customers in the foothills of the alpine region in north-east Victoria.

MYT is a winter peaking station and the peak electrical demand reached 13.4 MVA in the winter of 2024. The demand at MYT is forecast to increase to 18.2 MVA by 2029. The load transfer capability of the feeder interconnections between MYT and its neighbouring zone substations is approximately 1 MVA.

Table 15 shows the estimated magnitude of load at risk, annual hours at risk and both the magnitude and cost of expected unserved energy (EUSE) for winter.

Table 15: Expected 10% POE energy at risk at MYT Zone Substation.

MYT	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	15.9	16.0	16.2	16.5	16.7
10% POE Max Overload (%)	23.0	24.4	25.9	27.5	29.1
EUSE (MWh)	104.7	123.9	147.7	177.0	210.6
Hours at Risk (h)	118.4	131.1	152.5	179.7	206.2

A summary of the 5 -scale Likelihood of Failure score of key assets at MYT Zone Substation is provided in Figure 21 below.

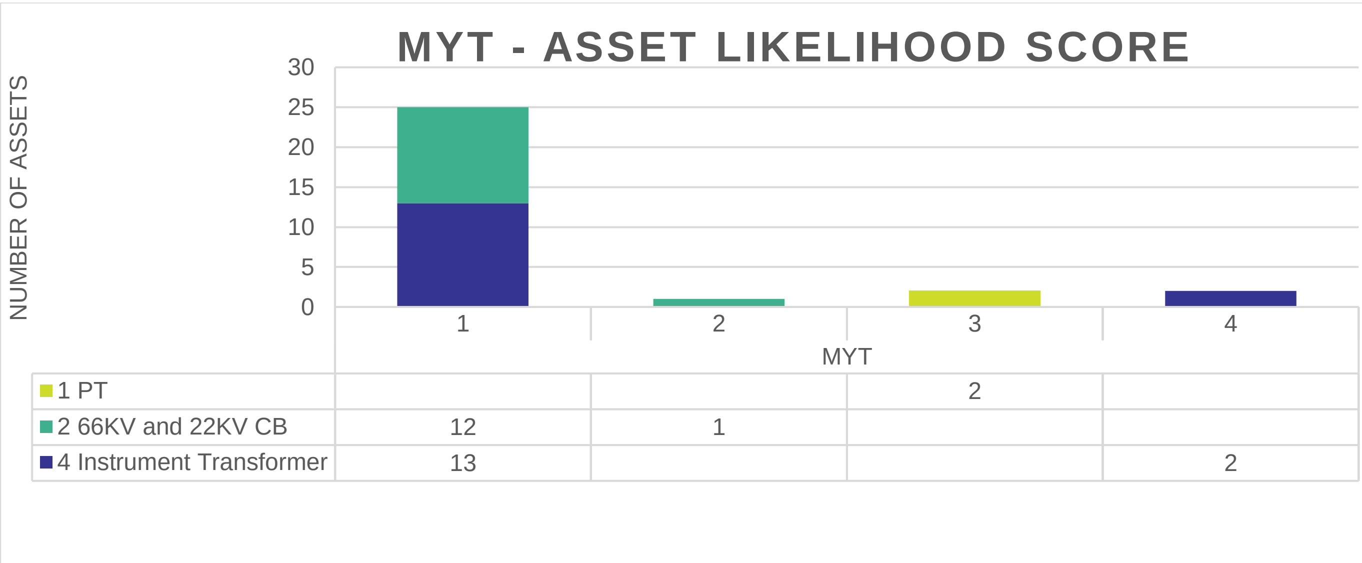


Figure 21: Number of Assets by Likelihood Score at KLO Zone substation.

6.2.9. Newmerella Zone Substation (NLA)

Newmerella (NLA) is located approximately 370km east of Melbourne (VicRoads map reference 85 H-5) and is the main source of supply for Newmerella, Orbost, Bemm River, Lake Tyers, and surrounding areas. NLA supplies 3,717 customers in total. The load at NLA includes town and rural based residential, with some town based commercial, industrial, and farming.

NLA is a winter peaking station and the peak electrical demand reached 7.5 MVA in winter 2024. The demand growth at NLA is forecast to be flat. The load transfer capability of the feeder interconnections between NLA and its neighbouring zone substations is approximately 2 MVA. This station does not have any load at risk driven by the increase in demand in the upcoming period.

A summary of the 5 -scale Likelihood of Failure score of key assets at NLA Zone Substation is provided in Figure 22 below.

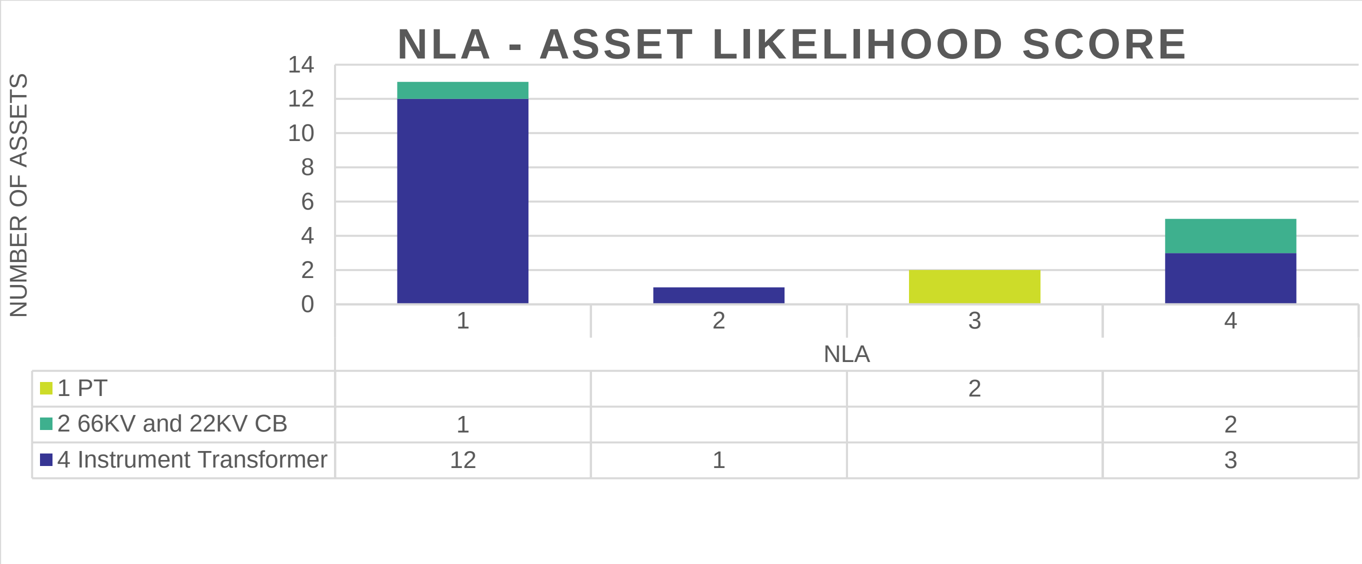


Figure 22: Number of Assets by Likelihood Score at NLA Zone substation.

The service level risk to customers supplied from NLA Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis identified the preferred option as replacing the transformers and 22kV switchgear by 2026.

6.2.10. Officer Zone Substation (OFR)

Officer (OFR) zone substation consists of two 66/22 kV 20/33 MVA transformers supplying a single 22 kV bus and four 22 kV feeder circuits. The substation supplies approximately 26,697 mostly residential and commercial customers in one of south-east Melbourne's major growth corridors.

OFR is a summer peaking station, and the peak electrical demand reached 48.1 MVA in the summer of 2023/24. Table 16 show the estimated magnitude of load at risk, annual hours at risk and the magnitude expected unserved energy (EUSE).

Table 16: Expected 10% POE energy at risk at OFR Zone Substation.

OFR	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	55.0	61.2	65.7	69.6	73.5
10% POE Max Overload (%)	13.2	25.9	35.3	43.2	51.2
EUSE (MWh)	23.0	112.6	229.9	381.5	598.3
Hours at Risk (h)	9.3	24.3	38.5	58.9	84.8

A summary of the 5 -scale Likelihood of Failure score of key assets at OFR Zone Substation is provided in Figure 23 below.

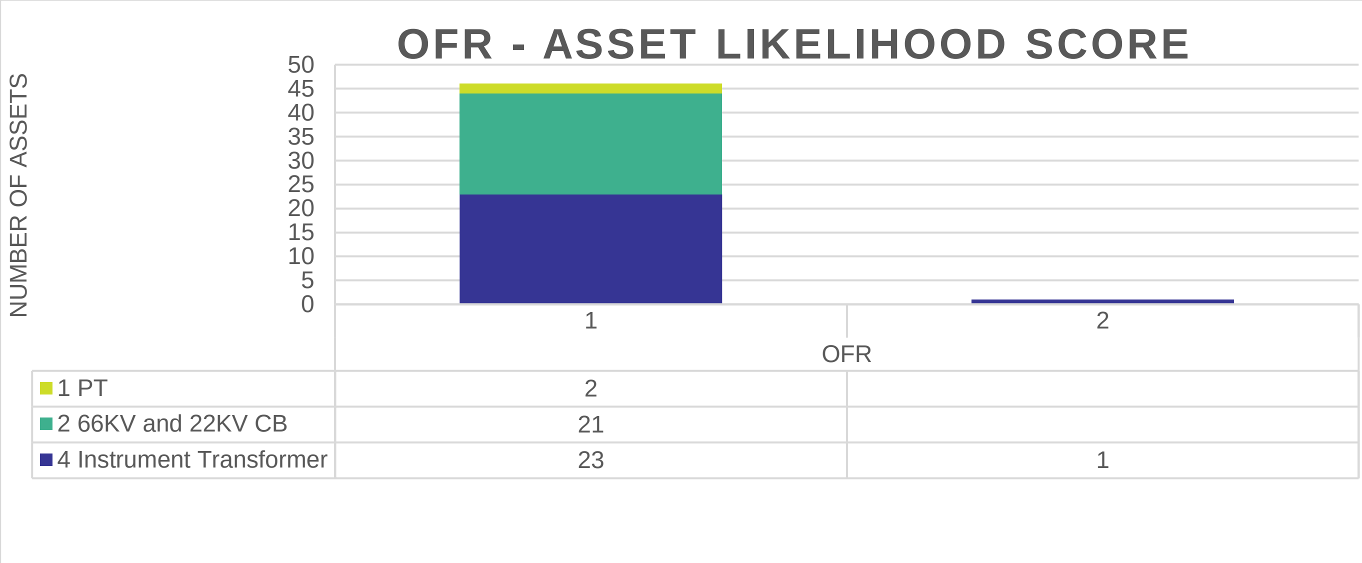


Figure 23: Number of Assets by Likelihood Score at OFR Zone substation.

6.2.11. Pakenham Zone Substation (PHM)

Pakenham (PHM) zone substation consists of two 66/22 kV 20/33 MVA transformers supplying two 22 kV buses and eight 22 kV feeder circuits. The substation supplies approximately 16,619 mostly residential customers in Melbourne's south-eastern suburbs.

EPG Zone Substation is a summer peaking station, and the peak demand reached 49.1 MVA in the summer of 2023/24. By 2029, this peak demand is expected to increase to 57.1 MVA. The load transfer capability of the feeder interconnections between PHM and its neighbouring zone substations is approximately 12.2 MVA. Table 17 shows the estimated magnitude of load at risk, annual hours at risk and the magnitude expected unserved energy (EUSE).

Table 17: Expected 10% POE energy at risk at PHM Zone Substation.

PHM	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	2025	2026	2027	2028	2029
10% POE Max Overload (%)	37.2	43.5	48.8	53.1	55.9
EUSE (MWh)	-15.2	-0.9	11.3	21.0	27.3
Hours at Risk (h)	0.0	0.0	14.5	103.3	216.6

There is a project to be delivered in the next EDPR period for a new zone substation to be constructed south of Pakenham. This will accommodate for the large and rapid growth of industrial and residential loads which is predicted over the next 5-10 years.

6.2.12. Seymour Zone Substation (SMR)

Seymour (SMR) zone substation consists of two 66/22 kV 20/33 MVA transformers supplying a two 22 kV buses and six 22 kV feeder circuits. The substation supplies approximately 10,880 residential, commercial, industrial customers in the precincts of Seymour, Nagambie and down to Yea.

SMR is a summer peaking station and the peak electrical demand reached 33.1 MVA in the summer of 2023/24. The demand at SMR is forecast to increase to 39.7 MVA by 2028/29. The load transfer capability of the feeder interconnections between SMR and its neighbouring zone substations is approximately 5.6 MVA. This station does not have any load at risk driven by the increase in demand in the upcoming period.

A summary of the 5 -scale Likelihood of Failure score of key assets at SMR Zone Substation is provided in Figure 24 below.

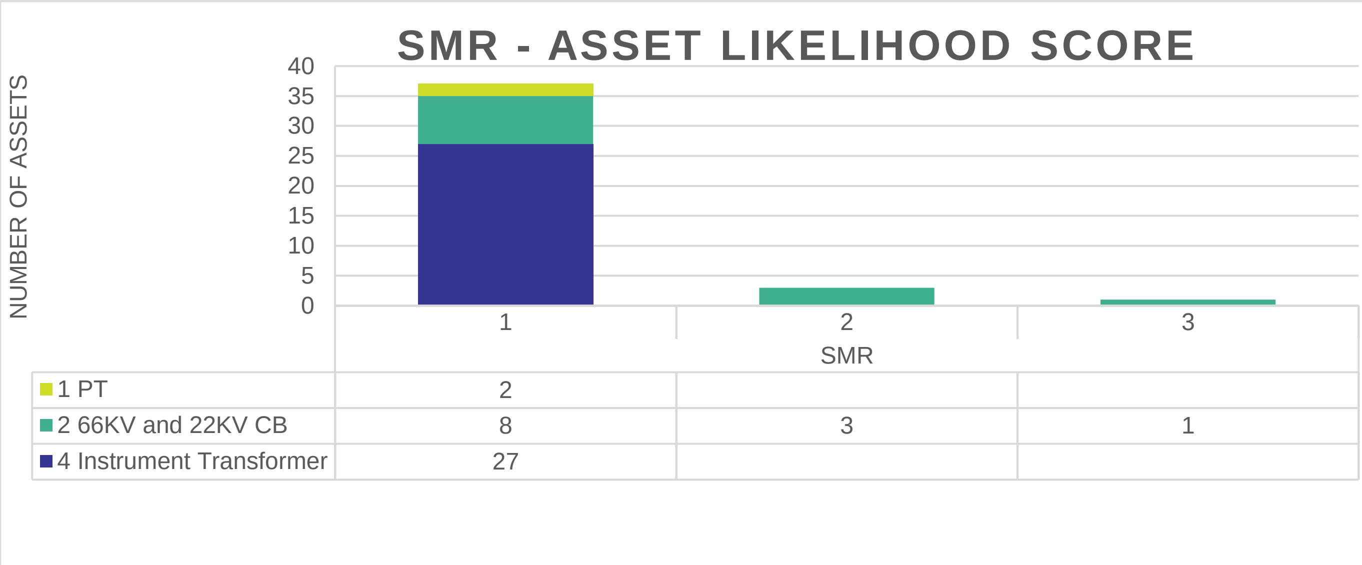


Figure 24: Number of Assets by Likelihood Score at SMR Zone substation.

6.2.13. Thomastown Zone Substation (TT)

Thomastown (TT) Zone Substation is located in the northern suburbs of metropolitan Melbourne. It is the main source of electricity for the suburbs of Thomastown, Lalor, Reservoir, Kingsbury and Bundoora. TT supplies approximately 29,500 customers, split evenly with AusNet supplying approximately 15,000 customers and Jemena supplying approximately 16,900 customers. The load at TT is urban in nature and includes mostly residential and industrial load with some commercial loads.

TT zone substation is a summer peaking station, and the peak electrical demand reached 76.1MVA in the summer of 2023/24. Table 15 shows the estimated magnitude of load at risk, annual hours at risk and the expected unserved energy (EUSE).

Table 15: Expected 10% POE energy at risk at TT Zone Substation.

TT	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	62.2	63.6	65.0	66.3	67.9
10% POE Max Overload (%)	6.1	8.5	10.9	13.1	15.8
EUSE (MWh)	27.5	88.1	190.3	330.5	559.6
Hours at Risk (h)	29.2	62.5	94.3	135.2	183.3

A summary of the 5 -scale Likelihood of Failure score of key assets at SMR Zone Substation is provided in Figure 25 below.

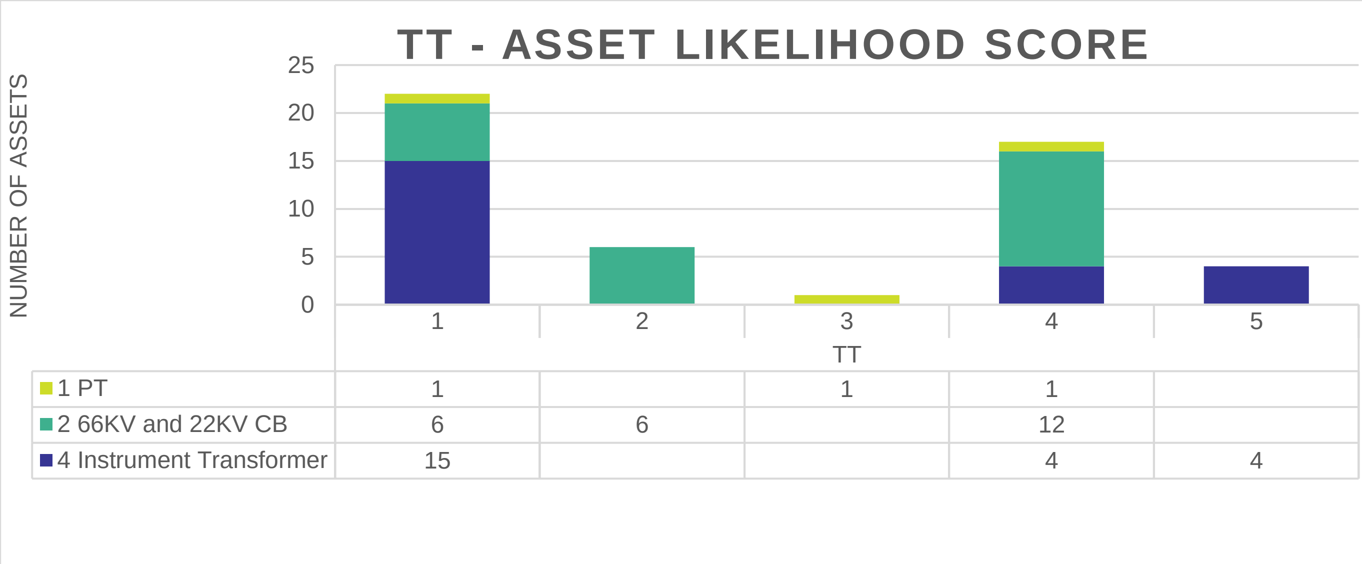


Figure 25: Number of Assets by Likelihood Score at TT Zone substation.

The service level risk to customers supplied from TT Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis and ARM data modelling identified the preferred option as replacing both the 66kV and 22kV circuit breakers by 2027.

6.2.14. Traralgon Zone Substation (TGN)

Traralgon (TGN) is located approximately 170km east of Melbourne and is the main source of supply for Traralgon, Glengarry, Callignee, Gormandale, Rosedale, and surrounding areas. TGN supplies approximately 18,300 customers. The load at TGN includes town and rural based residential, with some town based commercial, industrial, and farming.

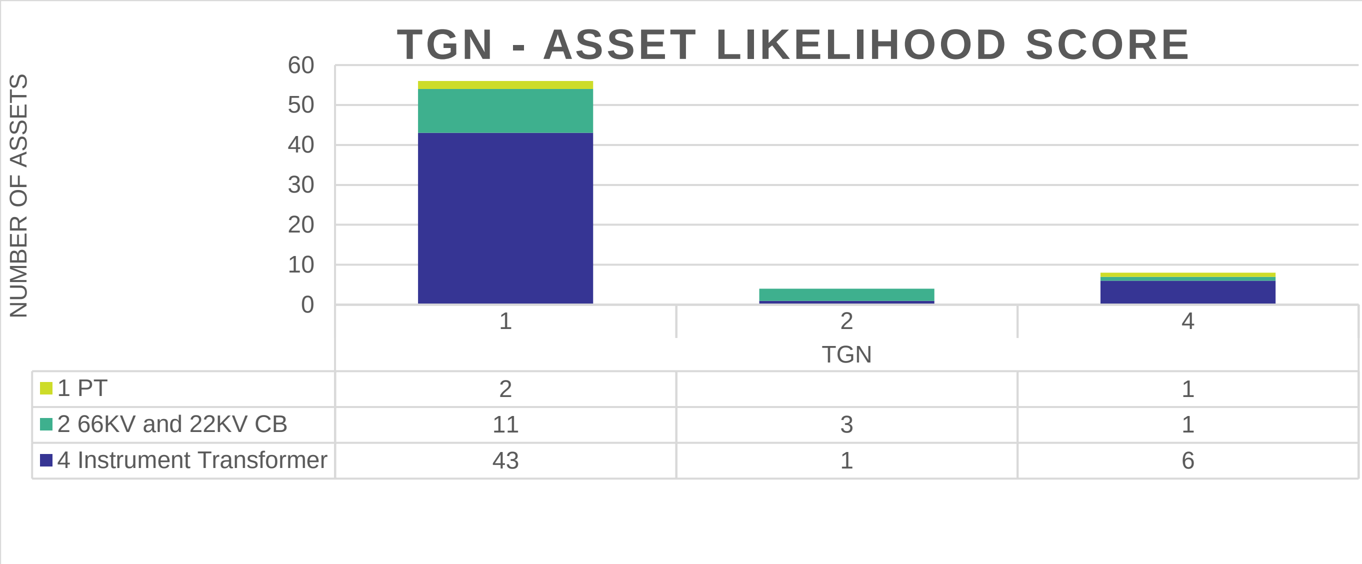
TGN is a summer peaking station and the peak electrical demand reached 43.5 MVA in the summer of 2023/24 and is forecasted to be 50.1 MVA in 2028/29. The load transfer capability of the feeder interconnections between TGN and its neighbouring zone substations is approximately 9 MVA.

Table 16 shows the estimated magnitude of load at risk, annual hours at risk and the magnitude expected unserved energy (EUSE).

Table 16: Expected 10% POE energy at risk at TGN Zone Substation

TGN	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	37.8	38.5	39.2	40.0	40.9
10% POE Max Overload (%)	4.5	6.4	8.4	10.6	13.0
EUSE (MWh)	1.8	3.0	4.6	6.7	9.3
Hours at Risk (h)	1.6	2.0	2.5	3.0	3.4

A summary of the 5 -scale Likelihood of Failure score of key assets at TGN Zone Substation is provided in Figure 26 below.



	1	2	4
1 PT	2		1
2 66KV and 22KV CB	11	3	1
4 Instrument Transformer	43	1	6

Figure 26: Number of Assets by Likelihood Score at TGN Zone substation.

The service level risk to customers supplied from TGN Zone Substation is forecast to grow to unacceptable levels.

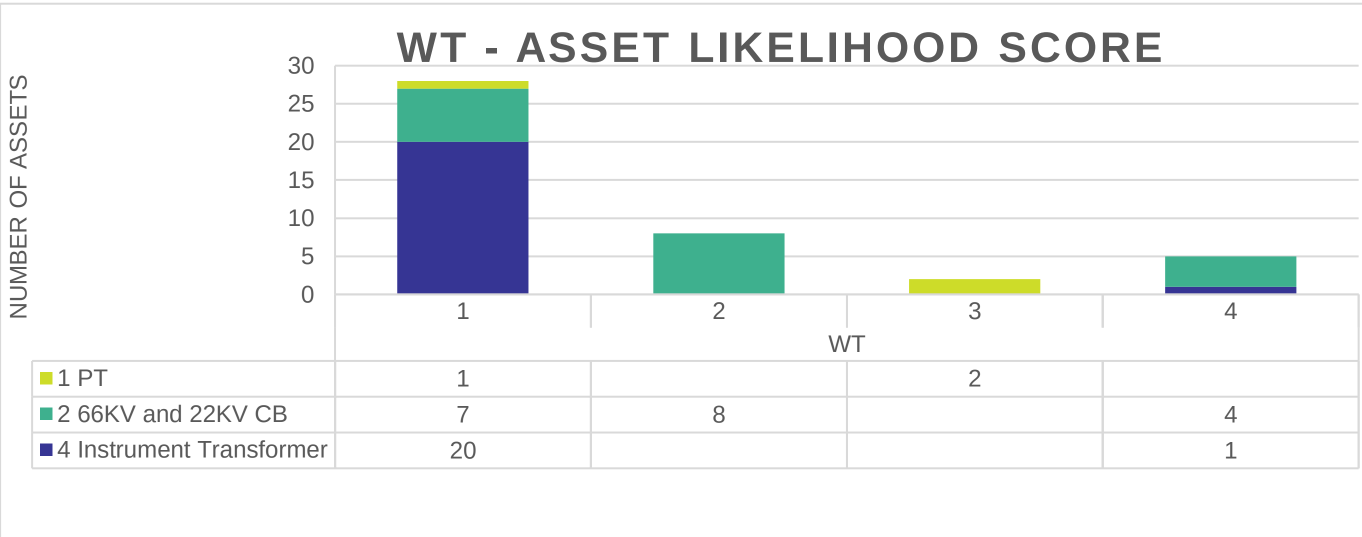
Consequently, the options analysis and ARM data modelling identified the preferred option as replacing one transformer and capacitor bank by 2025 and deferring one transformer, 66kV circuit breakers and 22kV switchgear into the next EDPR period.

6.2.15. Watsonia Zone Substation (WT)

Watsonia (WT) Zone Substation is located in the northern suburbs of metropolitan Melbourne approximately 20km north of Melbourne. WT is the main source of supply for the suburbs of Watsonia, Greensborough, Montmorency, Lower Plenty, Macleod and Bundoora. WT supplies approximately 26,748 AusNet customers and a portion of Jemena customers. The load at WT includes mostly residential and commercial urban load with some industrial loads and a few farm loads.

WT is a summer peaking station and the peak electrical demand reached 66.1 MVA in the summer of 2023/24. This station does not have any load at risk driven by the increase in demand in the upcoming period.

A summary of the 5 -scale Likelihood of Failure score of key assets at WT Zone Substation is provided in Figure 27 below.



	1	2	3	4
1 PT	1		2	
2 66KV and 22KV CB	7	8		4
4 Instrument Transformer	20			1

Figure 27: Number of Assets by Likelihood Score at WT Zone substation.

The service level risk to customers supplied from WT Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis and ARM data modelling identified the preferred option as replacing the 22kV circuit breakers by 2027.

6.2.16. Wangaratta Zone Substation (WN)

Wangaratta zone substation (WN) is located in north-east of Victoria and supplies approximately 18,242 AusNet customers. The load at WN includes a mix of residential, farming, commercial and large industrial loads.

WN is a summer peaking station and the peak electrical demand reached 44.6 MVA in the summer of 2023/24. The load transfer capability of the feeder interconnections between WN and its neighbouring zone substations is approximately 7 MVA.

Table 17 shows the estimated magnitude of load at risk, annual hours at risk and the magnitude expected unserved energy (EUSE).

Table 17: Expected 10% POE energy at risk at WN Zone Substation

WN	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	43.6	44.1	44.8	45.5	46.2
10% POE Max Overload (%)	17.3	18.7	20.3	22.2	24.3
EUSE (MWh)	26.6	34.5	46.2	61.9	82.1
Hours at Risk (h)	15.9	19.2	23.4	28.0	32.9

A summary of the 5 -scale Likelihood of Failure score of key assets at WT Zone Substation is provided in Figure 28 below.

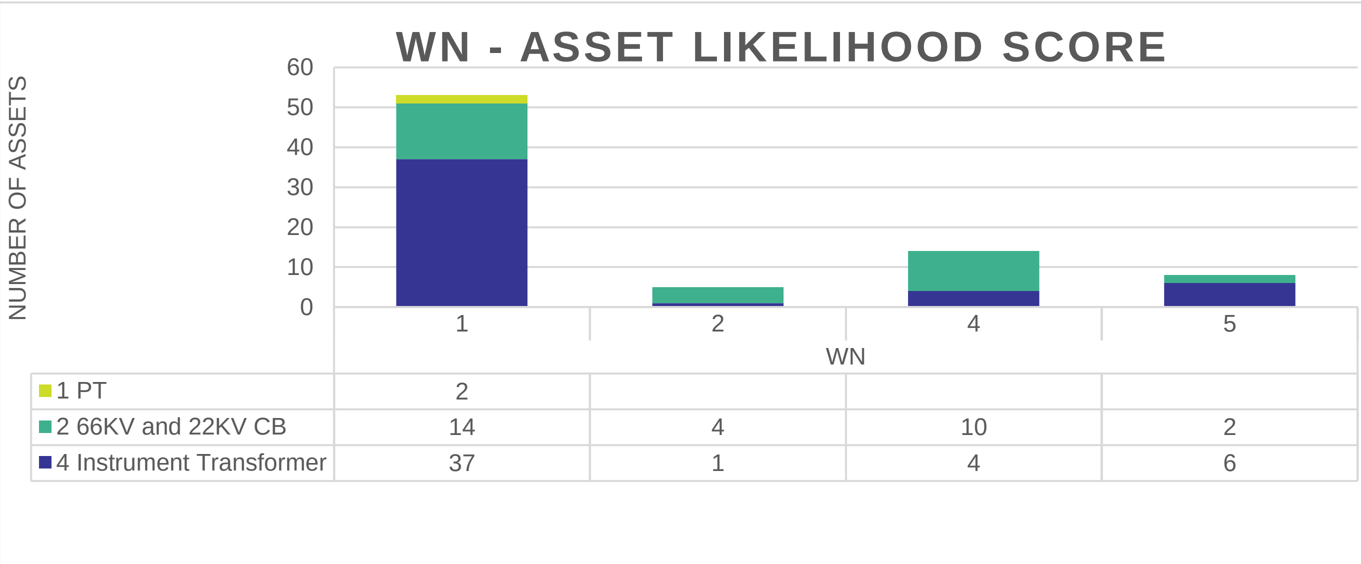


Figure 28: Number of Assets by Likelihood Score at WN Zone substation.

6.2.17. Warragul Zone Substation (WGL)

Warragul (WGL) is located approximately 100km south east of Melbourne and is the main source of supply for the suburbs of Warragul, Drouin, Longwarry, Bunyip, Darnum, Noojee, and surrounding areas. WGL supplies approximately 25,400 AusNet customers. The load at WGL includes mostly residential with some farming, commercial and industrial loads.

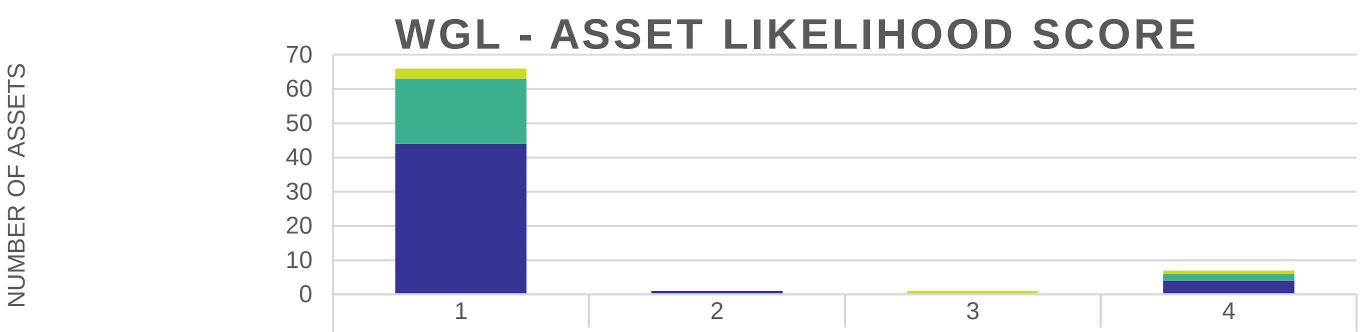
WGL is a summer peaking station and the peak electrical demand reached 68.2 MVA in the summer of 2023/24. The load transfer capability of the feeder interconnections between WGL and its neighbouring zone substations is approximately 8 MVA.

Table 18 shows the estimated magnitude of load at risk, annual hours at risk and the magnitude expected unserved energy (EUSE).

Table 18: Expected 10% POE energy at risk at WGL Zone Substation

WGL	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	70.2	72.3	74.4	76.5	78.8
10% POE Max Overload (%)	13.5	16.8	20.1	23.6	27.3
EUSE (MWh)	29.2	49.5	78.2	121.1	181.7
Hours at Risk (h)	8.6	12.6	19.1	26.4	36.2

A summary of the 5 -scale Likelihood of Failure score of key assets at WGL Zone Substation is provided in Figure 29 below.



	1	2	3	4
1 PT	3		1	1
2 66KV and 22KV CB	19			2
4 Instrument Transformer	44	1		4

Figure 29: Number of Assets by Likelihood Score at WGL Zone substation.

The service level risk to customers supplied from WGL Zone Substation is forecast to grow to unacceptable levels. Consequently, the options analysis and ARM data modelling identified the preferred option as replacing four transformers with two transformers, replace the existing capacitor bank and install two new 66kV circuit breakers.

6.2.18. Wonthaggi Zone Substation (WGI)

Wonthaggi (WGI) ZSS is a REFCL site consisting of 3x 13.5MVA 66/22kV transformers supplying 2x buses with 4 feeders each. The assets of concern are referred to thusly,

Bus 2, supplied by

- Transformer No. 1
- Transformer No. 2

Bus 3, supplied by

- Transformer No. 3

In the past the two buses at WGI would be connected, allowing for the load of both buses to be shared across the three transformers. This was particularly helpful for Bus 3 which has historically experienced higher load than Bus 1 but is only connected to a single transformer (No. 3).

However, the connected bus configuration can no longer be maintained due to REFCL compliance works. Where in order to meet capacitance requirements for REFCL compliance an additional REFCL GFN has been installed at WGI. The normal operation of the buses will be split, each having it's individual GFN, when REFCL operation at Setpoint 1 is required.

Combined with the odd number of transformers, this means that one of the buses (4 feeders) will only be supplied by a single transformer, resulting in increased risk of overloading as well as not having N-1 capability for the bus. These risks are significant and become more pronounced based on the forecasted increase in load.

WGI is a summer peaking station and the peak electrical demand reached 43.5 MVA in summer 2023/24, and is forecast to grow to 49.0 MVA by 2028/29. The load transfer capability of the feeder interconnections between WGI and its neighbouring zone substations is 4 MVA.

Table 19 shows the estimated magnitude of load at risk, annual hours at risk and the magnitude expected unserved energy (EUSE).

Table 19: Expected 10% POE energy at risk at WGI Zone Substation

WGI	2025	2026	2027	2028	2029
10% POE Max Load at Risk (MVA)	42.5	43.4	44.4	45.3	46.2
10% POE Max Overload (%)	11.2	13.7	16.2	18.6	21.0
EUSE (MWh)	6.4	10.7	18.0	27.4	41.0
Hours at Risk (h)	3.2	6.6	10.0	14.0	19.7

A summary of the 5 -scale Likelihood of Failure score of key assets at WGL Zone Substation is provided in Figure 30 below.

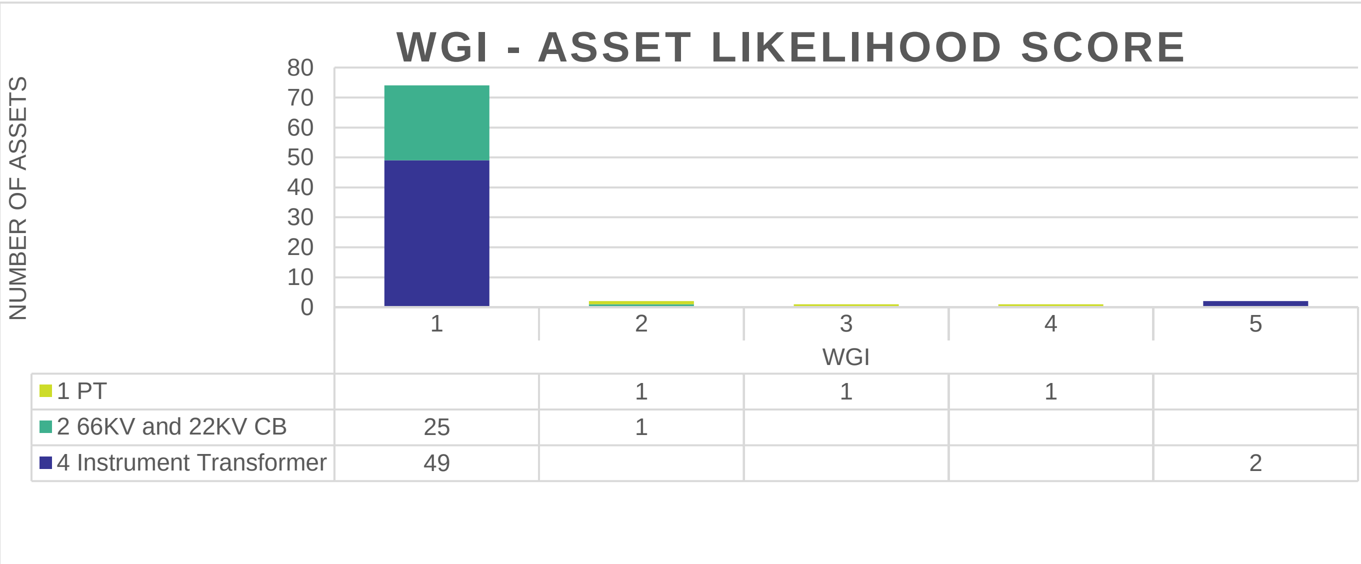


Figure 30: Number of Assets by Likelihood Score at WGI Zone substation.

6.3. Transmission connection asset export limitations

This section discusses identified transmission-distribution connection point export limitations. It assesses the limitation, its impact and, where possible, suggests potential solutions. Some minor limitations that exist under contingency conditions, but where there is negligible generation at risk, are not discussed in detail in this section, but are reported in the tables of Section 4.6.4.

Table 24 shows the estimated magnitude of generation at risk of curtailment for 10% conditions, for each terminal station that has identified export limitations.

Table 24: Estimated generation at risk on terminal stations with export limitations

Terminal Station	Generation at Risk (MW) 10%POE 2024	2025	2026	2027	2028
Nil	-	-	-	-	-

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

6.4. Sub-transmission line export limitations

This section discusses identified sub-transmission line export limitations. It assesses the limitation, its impact and, where possible, suggests potential solutions. Some minor limitations that exist under contingency conditions, but where there is negligible generation at risk, are not discussed in detail in this section, but are reported in the tables of Section 4.6.5.

Table 25 shows the estimated magnitude of generation at risk of curtailment for 10% conditions, for each subtransmission loop that has identified export limitations.

Table 25: Estimated generation at risk on sub-transmission loops with export limitations

Sub-T Loop	Generation at Risk (MW) 10%POE 2025	2026	2027	2028	2029
CBTS-CRE	12.1	15.6	18.2	20.2	21.9
CBTS-LYD-NRN-PHM-OFR-BWN-LLG-CLN-CBTS	137.8	156.0	171.1	182.4	192.5
ERTS-BGE-FGY-ERTS	19.0	20.8	21.9	22.6	23.1
ERTS-DN-HPK-DSH-DVY-ERTS	33.1	35.8	38.0	39.6	40.8
GNTS-BN-MSD-MJG	15.8	17.9	19.5	20.6	21.5
GNTS-WN	16.7	18.6	20.2	21.4	22.3
MWTS-LGA-FTR-MWTS	51.8	56.5	60.4	63.2	65.5
MWTS-TGN-SLE-MFA-BDSS-BDL	49.6	55.8	60.8	64.3	67.2
MWTS-YPS-MOE-WGL-MWTS	26.8	30.4	33.2	35.1	36.7
SMTS-EPG-SMTS	31.9	36.3	39.8	42.4	44.6
SMTS-DRN-KLK-MDI-RUBA-YEA-SMR-KMS-KLO-SMTS	101.9	114.2	125.0	134.1	142.5

SMTS-SMG	3.6	4.5	5.2	5.6	5.9
WOTS-WO-BWA	8.3	9.8	11.0	11.8	12.5
MBTS-MBY	2.0	2.2	2.3	2.5	2.5
MBTS-BRT-MYT	7.8	8.8	9.7	10.2	10.7
TTS-NEI-NH-WT-YYS	2.3	3.6	4.5	5.1	5.5

AusNet is currently investigating a range of options to alleviate forecast export limitations on our sub-transmission loops including (among others):

- Option 1: Review opportunities to reduce upstream terminal station float voltages;
- Option 2: Introduce LDC settings at upstream terminal stations;
- Option 3: Non-network options including generation curtailment support, demand response and/or reactive power network support;
- Option 4: Installation of reactors at the upstream terminal station to increase the available tapping range of power transformers at minimum demand;
- Option 5: Network reconfigurations and augmentations;
- Option 6: Engage with AEMO for opportunities to reduce transmission voltages at minimum demand;
- Option 7: Explore opportunities to change the terminal station power transformer tap changer specification to include buck taps; and
- Option 8: Engage with AEMO to adapt the existing switching control system for capacitor banks at terminal stations, to consider power transformers' tap position in its switching decision.

AusNet will continue to monitor the declining minimum demand levels on these sub-transmission loops and explore the feasibility of specific options to alleviate these forecast export limitations on a case-by-case basis.

6.5. Zone substation export limitations

This section discusses identified zone substation export limitations. It assesses the limitation, its impact and, where possible, suggests potential solutions. Some minor limitations that exist under contingency conditions, but where there is negligible generation at risk, are not discussed in detail in this section, but are reported in the tables of Section 4.6.6.

Table 26 shows the estimated magnitude of generation at risk of curtailment for 10% PoE conditions, for each zone substation that has identified export limitations.

Table 26: Estimated generation at risk on zone substations with export limitations

Zone Substation	Generation at Risk (MW)				
	10%POE				
	2025	2026	2027	2028	2029
BDL	13.2	15.4	17.2	18.5	19.6
BGE	3.2	3.9	4.5	4.8	5.1
BN	8.8	10.0	10.8	11.3	11.8

BRA	2.7	4.4	5.6	6.3	6.9
BRT	2.8	3.1	3.5	3.7	3.8
BWA	1.7	1.8	1.9	2.0	2.0
BWN	4.3	5.0	5.6	6.0	6.2
CLN	37.9	48.2	57.0	63.9	70.2
CNR	0.7	0.8	0.9	0.9	1.0
CRE	12.1	15.6	18.2	20.2	21.9
DRN	16.4	19.9	22.6	24.6	26.3
EPG	28.0	32.3	35.8	38.4	40.6
FGY	10.4	11.4	12.0	12.4	12.7
FTR	4.8	5.4	6.0	6.3	6.6
HPK	13.9	16.7	18.9	20.5	21.6
KLK	2.2	2.4	2.6	2.8	2.9
KLO	22.8	29.2	35.3	41.0	46.5
KMS	5.3	6.0	6.7	7.1	7.6
LDL	2.3	3.7	4.9	5.7	6.3
LGA	5.8	6.8	7.6	8.1	8.6
LLG	4.6	5.4	6.0	6.4	6.8
LYD	3.1	3.9	4.5	4.9	5.2
MBY	2.0	2.2	2.3	2.5	2.5
MFA	5.6	6.4	6.9	7.3	7.6
MOE	10.0	11.0	11.8	12.3	12.8
MSD	7.4	8.2	9.0	9.5	10.0
MWL	3.8	4.8	5.5	6.0	6.4
MYT	4.7	5.4	5.9	6.2	6.5
NLA	2.8	3.2	3.4	3.6	3.8
OFR	13.3	17.0	19.9	22.1	24.1

PHI	8.3	9.3	10.1	10.6	11.1
RUBA	5.9	6.3	6.6	6.8	7.0
RVE	6.5	7.3	7.9	8.3	8.7
SMG	2.3	3.2	3.8	4.2	4.5
SMR	5.6	6.7	7.6	8.2	8.7
TGN	10.4	12.2	13.7	14.8	15.6
WGI	20.3	22.4	24.1	25.4	26.6
WGL	13.6	16.2	18.2	19.6	20.8
WN	10.0	11.9	13.5	14.6	15.6
WO	6.6	8.0	9.1	9.9	10.4
WOTS	25.0	28.1	30.4	31.9	33.0
WYK	3.9	4.9	5.7	6.3	6.7

AusNet is currently investigating a range of options to alleviate forecast export limitations on our zone substations including (among others):

- Option 1: Review opportunities to reduce zone station float voltages;
- Option 2: Introduce LDC settings at zone substations;
- Option 3: Non-network options including generation curtailment support, demand response and/or reactive power network support;
- Option 4: Installation of reactors at the zone substation to increase the available tapping range of power transformers at minimum demand;
- Option 5: Network reconfigurations and augmentations;
- Option 6: Application of Dynamic Voltage Management capability at the zone substation (an enhanced voltage control system informed by a near-real time AMI voltage data feedback loop);
- Option 7: Explore opportunities to change the zone substation power transformer tap changer specification to increase the number of buck taps;
- Option 8: Optimise existing capacitor bank switching settings at zone substations; and
- Option 9: Introduce a power transformer tap position control logic interlock, applied to capacitor bank switching relays at zone substations.

AusNet will continue to monitor the declining minimum demand levels on these zone substations and explore the feasibility of specific options to alleviate these forecast export limitations on a case-by-case basis.

7. System Limitations for Primary Distribution Feeders

7.1. Primary distribution feeders import limitations

This section outlines the primary distribution feeders that are currently or are forecast to be import limited (i.e., overloaded) within the next two years. This section addresses the requirements of the NER schedule 5.8 (d). The name of the feeder indicates its location based on the zone substation, such as BN11 from BN zone substation.

Distribution feeders that are overloaded or are forecast to become overloaded in the next two years are presented in Table 27, along with the extent of the forecast overload and the number of customers that the feeder supplies.

Table 27: Import limited (Overloaded) feeders for 50% and 10% probability of exceedance conditions

Feeder	Number of customers	Summer import rating (A)	Maximum Load at Risk (Amps)					
			50%POE			10%POE		
			2024/25	2025/26	2026/27	2024/25	2025/26	2026/27
BDL32	3629	285	-	-	-	-	-	5
BN11	4766	285	5	8	11	32	36	40
BWN12	1318	312	8	10	13	30	32	34
CLN11	8119	375	84	130	181	155	208	266
CLN12	6111	335	-	-	-	10	13	16
CLN13	6995	344	-	7	19	34	48	62
CLN14	5585	325	-	12	26	41	58	75
CLN21	5886	358	-	-	-	6	14	21
CLN23	4831	323	-	5	23	49	69	89
CLN24	1327	360	-	-	-	-	-	233
CRE21	5131	375	-	-	-	-	-	14
CRE31	6275	375	-	-	5	6	25	41
CRE33	4309	335	-	-	-	-	8	29
ELM21	2449	258	-	-	-	4	7	10
ELM34	4215	320	-	-	-	2	4	8
EPG12	6390	340	-	-	-	-	2	17
EPG13	6581	365	22	70	120	94	149	207
EPG33	418	385	-	-	-	11	62	122
EPG35	300	350	-	38	102	44	121	195
FGY14	2700	250	-	-	-	6	7	9
HPK21	5329	315	11	30	54	185	207	236
HPK22	4699	311	-	-	-	6	12	17
HPK24	1563	316	-	-	1	15	18	22

KLO14	9405	360	82	155	250	133	216	321
KLO24	7634	360	49	78	121	94	130	180
MOE13	730	205	-	-	-	15	16	18
MOE23	2448	180	4	4	6	16	17	19
MSD4	3029	230	-	-	-	5	10	15
OFR21	4340	375	-	-	-	-	1	7
PHI12	5060	285	-	-	-	-	-	5
RVE12	3712	360	-	-	-	124	90	63
RVE13	3800	352	-	-	-	159	125	96
SMR14	2433	157	14	15	18	24	27	30
SMR24	3610	350	-	-	-	-	-	1
TGN11	4309	280	-	-	-	19	23	28
TGN31	2180	180	6	10	13	65	66	70
TGN43	3724	265	-	-	-	1	1	1
TT5	1859	256	-	-	-	17	21	24
WGI23	2891	180	-	-	-	20	26	31
WGL13	5099	325	-	5	14	22	31	42
WGL15	2992	285	-	-	-	4	7	9
WOTS11	3751	290	-	-	-	-	1	12
WOTS25	3622	260	-	-	-	-	9	20
WT5	1438	250	-	-	-	9	11	13
WT9	3001	254	-	-	-	-	-	2

There are 25 feeders during winter periods that are currently or forecast to be overloaded from 2024/25.

Table 28 provides details of the estimated reduction in forecast load that would be required to eliminate a forecast feeder overload for a period of 12 months. The table covers a summary of the location of relevant connection points at which the estimated reduction in forecast load would defer the overload and the estimated reduction in forecast load in MW needed to defer the forecast system limitation. The estimate of the year in which the overload is forecast to occur is also provided.

Table 28: Details of load reduction required to defer limitation by one year

Feeder	Forecast Overload Timing	Load Reduction Required for 12-month deferral (MW)	Comments
BWN12	December 2025	0.5	Feeder can be risk managed until 2025. The proposed feeder ties will be completed in 2025. Non-network solutions will be considered.
CLN11	December 2025	2	Feeder can be risk managed until 2025. The proposed feeder ties will be completed in 2025. Non-network solutions will be considered.
CLN12	December 2025	0.5	Feeder can be risk managed until 2029. The proposed feeder ties will be completed in 2025. Non-network solutions will be considered.

CLN13	December, 2025	0.5	Feeder can be risk managed until 2026. The proposed feeder ties will be completed in 2025. Non-network solutions will be considered.
CLN14	December, 2025	0.1	Feeder can be risk managed until 2025. The proposed feeder tie may be completed by 2025. Non-network solutions will be considered.
CLN23	December, 2026	0.1	Feeder can be risk managed until 2028. The proposed feeder tie may be completed by 2025. Non-network solutions will be considered.
CRE21	December 2026	0.5	Feeder can be risk managed until 2026. Non-network solutions will be considered.
CRE31	December, 2025	0.2	Feeder can be risk managed until 2025. Non-network solutions will be considered.
CRE33	December, 2025	0.5	Feeder can be risk managed until 2025. Non-network solutions will be considered.
ELM21	December, 2025	0.2	Feeder can be risk managed until 2025. Non-network solutions will be considered.
ELM34	December 2025	0.1	Feeder can be risk managed until 2025. Non-network solutions will be considered.
EPG12	December, 2025	0.2	Feeder can be risk managed until 2027. New feeder ties are expected to be completed in 2025. Non-network solutions will be considered.
EPG13	December, 2025	1.6	Feeder can be risk managed until 2026. New feeder ties are expected to be completed in 2025. Non-network solutions will be considered.
EPG32	December, 2025	0.7	Feeder can be risk managed until 2026. New feeder ties are expected to be completed in 2025. Non-network solutions will be considered.
EPG33	December, 2025	0.5	Feeder can be risk managed until 2026. Reconfiguration with surrounding feeders will be carried out. Non-network solutions will be considered.
EPG35	December,2025	2.2	Feeder can be risk managed until 2025. Reconfiguration with surrounding feeders will be carried out.
FGY14	December 2025	0.5	Feeder can be risk managed until 2025. Non-network solutions will be considered.
HPK21	December 2025	0.5	Feeder can be risk managed until 2025. Non-network solutions will be considered.

HPK22	December 2025	0.5	Feeder can be risk managed until 2025. Non-network solutions will be considered.
HPK24	December 2025	0.5	Feeder can be risk managed until 2025. Non-network solutions will be considered.
KLO14	December, 2025	3	Feeder can be risk managed until 2025. New feeder ties are expected to be completed in 2025. Non-network solutions will be considered.
KLO24	December, 2025	2	Feeder can be risk managed until 2024. The proposed new feeder may be completed in 2025. Non-network solutions will be considered.
MOE13	December 2025	0.5	Feeder can be risk managed until 2025. Non-network solutions will be considered.
MOE23	December 2025	0.5	Feeder can be risk managed until 2025. Non-network solutions will be considered.
MSD4	December 2025	0.2	Feeder can be risk managed until 2025. Non-network solutions will be considered.
MYT12	December 2026	0.1	Feeder can be risk managed until 2026. Non-network solutions will be considered.
OFR21	December, 2025	0.1	Feeder can be risk managed until 2027. The proposed new feeder tie may be completed during 2025. Non-network solutions will be considered.
RVE13	December, 2025	0.1	Feeder can be risk managed until 2029. Non-network solutions will be considered.
BN11	December 2025	2.6	Approximately 2.6MW temporary generation support will be used on days when the feeder load reaches over 275 A, depending on overloaded amount. 400 kW demand management is currently contracted. Non-network solutions will be considered. Proposed project in 2026-31 EDPR submission to offload feeder.
SMR14	December 2025	1.4	600 kW demand management is currently contracted. Non-network solutions will be considered for future years.
SMR24	December 2025	1.1	150 kW demand management recently contracted. RMR will be utilised during peak load conditions. A non-network solution is being considered for future years. Proposed project in 2026-31 EDPR submission to offload feeder.

TGN11	December 2025	0.7	Feeder can be risk managed until 2025. Non-network solutions will be considered.
TGN31	December 2026	TBA	TBA
WGI23	December 2025	0.2	Feeder can be risk managed until 2025. Non-network solutions will be considered.
WN2	December 2025	0.1	Feeder can be risk managed until 2029 with temporary transfers.
WN3	December, 2025	0.1	Feeder can be risk managed until 2032 with temporary transfers.
PHI12	December 2025	0.1	Thermal upgrade of a feeder section is required. Temporary generation close to the race track may be required as the PICESS battery does not address this constraint.
PHI13	December, 2025	0.3	Feeder can be risk managed until 2030. Transfers may be possible.
WGL13	December 2025	0.75	Coupled with load transfers onto WGL12 the West Gippsland (Longwarry) battery will help alleviate summer peak demand on this feeder. This has deferred a new 22 kV feeder supplied out of WGL zone substation, but the long-term growth trend will necessitate construction of the feeder. Proposed project in 2026-31 EDPR submission to offload WGL feeders.
WOTS25	December 2025	0.5	Feeder can be risk managed until 2026. Transfers may be possible. Non-network solutions will be considered. Proposed project in 2026-31 EDPR submission to offload feeder.
WT5	December 2025	1	Feeder can be risk managed until 2025. Transfers may be possible. Non-network solutions will be considered
WT9	December 2028	0.5	Feeder can be risk managed until 2028. Transfers may be possible. Non-network solutions will be considered

7.2. Primary distribution feeder export limitations

This section outlines the primary distribution feeders that are currently or are forecast to be export limited within the next two years. This section addresses the requirements of the NER schedule 5.8 (d1).

Distribution feeders that are currently or forecast to be export limited in the next two years are presented in Table 29, along with the extent of the generation at risk of curtailment and the number of customers the feeder supplies.

Table 29: Export limited feeders for 50% and 10% probability of exceedance conditions

Primary Distribution Feeder	No. Cust.	Export Rating (MW)	Generation at Risk (MW)					
			10% POE			50% POE		
			2025	2026	2027	2025	2026	2027
BDL31	3786	0.0	3.2	3.4	3.6	2.4	2.6	2.8
BDL32	3629	0.0	3.4	3.7	3.9	2.6	2.9	3.1
BDL33	1221	0.0	0.6	0.7	0.8	0.2	0.3	0.3
BDL34	5309	0.0	5.3	5.7	6.0	4.4	4.8	5.2
BDL41	4202	0.0	2.9	3.2	3.5	2.3	2.6	2.9
BDL44	2694	0.0	2.9	3.0	3.2	2.2	2.4	2.5
BN11	4752	0.0	2.7	3.0	3.2	2.2	2.4	2.5
BN12	783	0.0	1.0	1.1	1.2	0.7	0.8	0.9
BN22	3508	0.0	2.8	3.1	3.4	2.6	2.9	3.1
BN23	2492	0.0	3.2	3.4	3.7	2.8	3.1	3.3
BN24	1118	0.0	2.0	2.1	2.2	1.5	1.6	1.7
BRT22	1726	0.0	1.0	1.1	1.3	0.6	0.7	0.8
BWA22	1504	0.0	1.9	2.1	2.2	1.6	1.7	1.8
BWA23	455	0.0	0.6	0.7	0.7	0.2	0.2	0.2
CLN11	10365	-1.6	15.8	17.9	19.6	12.6	14.2	15.5
CLN13	4965	-11.9	4.8	5.8	6.6	3.0	3.8	4.5
CLN14	6026	-11.6	1.8	3.0	4.1	0.5	1.7	2.7
CRE33	4309	-0.9	3.6	4.1	4.5	2.7	3.3	3.5
DRN22	4288	0.0	9.9	10.2	10.5	9.3	9.6	9.8
DRN23	2663	-1.0	1.1	1.3	1.4	0.6	0.8	0.9
ELM26	3164	-2.3	0.6	0.9	1.1	0.2	0.5	0.7

ELM32	2814	-0.1	1.8	2.0	2.2	1.3	1.5	1.7
EPG13	6408	-0.1	15.6	17.4	18.8	13.9	15.4	16.6
EPG21	162	-13.7	101.7	114.2	112.7	17.6	15.4	4.3
EPG32	3965	-4.6	5.7	6.0	6.2	4.5	4.8	4.9
FGY21	1103	0.0	1.8	1.9	2.0	1.3	1.4	1.5
FTR12	1645	0.0	0.5	0.6	0.7	0.3	0.3	0.4
FTR21	2473	0.0	1.9	2.1	2.2	1.6	1.7	1.8
FTR22	1436	0.0	1.5	1.6	1.7	1.1	1.2	1.3
FTR23	3587	0.0	1.9	2.2	2.3	1.3	1.5	1.6
KLO14	9634	0.0	19.7	22.5	24.9	15.9	18.2	20.1
KLO24	7813	-5.8	4.0	5.1	6.0	2.8	3.8	4.5
KMS11	2145	0.0	1.8	1.9	2.1	1.5	1.6	1.8
KMS12	4783	0.0	3.3	3.6	3.9	2.5	2.8	3.0
LDL13	4087	-0.2	3.9	4.2	4.4	3.2	3.5	3.7
LDL14	2311	-0.4	0.8	1.0	1.0	0.3	0.5	0.5
LGA11	1724	0.0	1.3	1.4	1.5	1.0	1.1	1.2
LGA12	1052	0.0	0.9	0.9	1.0	0.5	0.5	0.6
LGA14	1711	0.0	1.9	2.1	2.2	1.5	1.7	1.8
LGA21	1958	0.0	2.0	2.2	2.3	1.7	1.9	2.0
LGA22	2085	0.0	0.9	1.0	1.1	0.5	0.7	0.8
LLG13	1482	0.0	1.4	1.5	1.6	0.8	0.9	0.9
LLG14	2804	0.0	1.8	2.1	2.2	1.4	1.6	1.8
MDG1	741	0.0	0.2	0.2	0.2	0.1	0.1	0.2
MFA21	2850	0.0	2.5	2.8	3.0	1.9	2.2	2.3
MFA22	1608	0.0	3.4	3.5	3.6	2.6	2.7	2.7
MFA31	2320	0.0	1.6	1.8	1.9	1.3	1.4	1.5
MFA34	1588	0.0	2.2	2.4	2.5	1.7	1.8	1.9
MOE12	1213	0.0	1.3	1.4	1.4	1.0	1.1	1.2
MOE13	730	-1.8	6.7	6.7	6.7	5.6	5.6	5.6
MOE15	1877	0.0	1.7	1.8	1.9	1.5	1.6	1.7

MOE21	2788	0.0	1.7	1.9	1.9	1.4	1.5	1.6
MOE23	2448	0.0	1.1	1.2	1.3	0.8	0.9	1.0
MSD1	2227	0.0	1.7	1.8	2.0	1.4	1.5	1.7
MSD2	1722	0.0	1.6	1.8	1.9	1.3	1.5	1.6
MSD4	3029	0.0	4.2	4.6	5.0	3.6	4.0	4.3
MWE5	37	0.0	204.2	220.6	221.6	110.7	114.8	105.9
MWL11	1424	-1.0	0.5	0.6	0.6	0.2	0.3	0.4
MWL16	1741	-1.0	0.4	0.5	0.6	0.1	0.2	0.3
MWL22	2986	0.0	0.3	0.5	0.6	0.1	0.3	0.3
MYT12	3289	0.0	3.6	3.9	4.1	3.0	3.3	3.5
MYT21	1872	0.0	1.9	2.1	2.3	1.6	1.8	2.0
NLA34	1578	0.0	1.2	1.3	1.5	0.7	0.9	1.0
PHI12	5054	0.0	8.2	8.6	8.9	7.7	8.1	8.4
PHI13	4825	0.0	2.2	2.5	2.7	1.8	2.1	2.4
PHM33	2790	-0.9	1.3	1.5	1.7	0.8	0.9	1.0
RUBA12	2733	0.0	2.2	2.4	2.5	1.5	1.7	1.8
RUBA22	1360	0.0	0.8	0.9	0.9	0.6	0.6	0.7
RUBA24	1065	-1.2	0.9	1.0	1.0	0.4	0.5	0.5
SLE14	4187	-0.2	1.6	1.8	2.0	1.3	1.5	1.7
SLE31	5269	0.0	3.9	4.1	4.4	3.4	3.7	4.0
SMR13	2840	0.0	1.3	1.5	1.6	0.9	1.1	1.2
SMR14	2433	0.0	2.1	2.3	2.4	1.7	1.9	2.0
SMR22	1574	0.0	1.0	1.2	1.2	0.8	0.9	1.0
SMR24	3688	0.0	2.5	2.8	3.0	1.9	2.2	2.5
TGN11	4309	0.0	3.5	3.8	4.1	2.9	3.3	3.6
TGN23	2480	0.0	2.7	2.9	3.1	2.3	2.5	2.7
TGN31	2180	0.0	3.2	3.4	3.5	2.7	2.8	3.0
TGN41	1901	0.0	2.4	2.7	2.9	2.0	2.3	2.4
TGN43	3724	0.0	2.1	2.4	2.6	1.6	1.9	2.1
UWY1	1072	0.0	0.3	0.4	0.5	0.2	0.3	0.4

WGI22	3249	-1.8	2.1	2.4	2.7	1.3	1.6	1.9
WGI23	2891	0.0	4.0	4.3	4.6	3.4	3.7	3.9
WGI24	3864	0.0	3.2	3.5	3.8	2.5	2.8	3.0
WGI31	3754	0.0	3.3	3.6	3.8	2.8	3.0	3.3
WGI32	4092	-2.3	1.7	2.1	2.4	0.8	1.2	1.5
WGI33	3265	0.0	2.3	2.6	2.8	1.8	2.0	2.2
WGL11	4327	0.0	3.5	3.8	4.1	2.7	3.0	3.3
WGL12	3824	0.0	3.7	3.9	4.1	2.9	3.2	3.3
WGL13	5049	0.0	3.3	3.7	4.0	2.8	3.1	3.3
WGL15	2992	0.0	0.7	0.9	1.0	0.1	0.3	0.4
WGL21	5121	0.0	4.4	4.9	5.2	3.7	4.1	4.4
WGL24	3741	0.0	1.6	1.9	2.1	1.1	1.3	1.5
WN2	3907	0.0	4.1	4.4	4.7	3.4	3.8	4.1
WN3	2971	0.0	4.2	4.5	4.7	3.6	3.8	4.1
WN4	2825	0.0	2.8	3.1	3.3	2.2	2.5	2.8
WN5	2477	0.0	3.4	3.6	3.7	2.6	2.8	3.0
WN6	4594	0.0	4.6	5.0	5.4	4.0	4.4	4.8
WO22	4277	0.0	3.2	3.6	3.9	2.4	2.7	3.0
WO32	2472	0.0	0.6	0.7	0.8	0.3	0.4	0.5
WOTS11	3751	0.0	6.4	6.9	7.2	5.6	6.1	6.4
WOTS13	2081	0.0	2.7	2.9	3.1	2.3	2.5	2.7
WOTS24	2163	0.0	2.0	2.3	2.5	1.5	1.8	2.0
WOTS25	3622	0.0	6.6	7.2	7.7	5.7	6.2	6.5
WYK23	3895	0.0	2.8	3.1	3.3	2.2	2.5	2.7
WYK24	3502	-0.4	1.3	1.5	1.7	0.9	1.1	1.3

AusNet is currently investigating a range of options to alleviate forecast export limitations on our primary distribution feeders including (among others):

- Option 1: Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators;
- Option 2: Non-network options including generation curtailment support, demand response and/or reactive power network support;
- Option 3: Network reconfigurations or augmentations to shorten feeders or split feeders;
- Option 4: Application of Dynamic Voltage Management capability at the upstream zone substation (an enhanced voltage control system informed by a near-real time AMI voltage data feedback loop); and

- Option 5: Optimisation of capacitor bank switching settings on existing in-line feeder shunt capacitor banks.

Table 30 provides details of the estimated reduction in forecast generation that would be required to eliminate a forecast feeder export limitation for a period of 12 months. The table covers a summary of the location of relevant connection points and the estimated reduction in forecast generation in MW needed to defer the forecast system limitation. The estimate of the year in which the limitation is forecast to occur is also provided.

Table 30: Details of generation reduction required to defer limitation by one year

Feeder	Forecast Limitation Timing	Generation Reduction Required for 12-month deferral (MW)	Comments
BDL34	2024	2.0	Application of Dynamic Voltage Management capability at the upstream zone substation
BDL41	2024	2.0	Application of Dynamic Voltage Management capability at the upstream zone substation
BDL44	2024	1.1	Application of Dynamic Voltage Management capability at the upstream zone substation
BN11	2024	3.0	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
BN23	2024	1.0	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
KMS12	2024	1.1	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.
MFA21	2024	1.7	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
MFA22	2024	5.1	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
MFA34	2024	1.2	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
MOE15	2024	1.2	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
MOE21	2024	1.0	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators

MSD1	2024	1.3	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.
MSD4	2024	2.9	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.
MYT12	2024	1.4	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.
PHI12	2024	2.4	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
SLE31	2024	2.8	Application of Dynamic Voltage Management capability at the upstream zone substation
TGN11	2024	2.1	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
TGN23	2024	1.5	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
TGN31	2024	1.6	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
TGN41	2024	1.1	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
WGI23	2024	2.6	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
WGI24	2024	3.3	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
WGI31	2024	2.3	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
WGI33	2024	1.1	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
WGL11	2024	1.7	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
WGL12	2024	1.6	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators

WGL13	2024	1.2	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
WGL21	2024	2.2	Introducing LDC settings at the upstream zone substations or in-line feeder voltage regulators
WN2	2024	2.5	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.
WN3	2024	2.2	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.
WN4	2024	1.4	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.
WN5	2024	2.4	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.
WN6	2024	2.2	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.
WO22	2024	2.8	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.
WOTS11	2024	3.9	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.
WOTS13	2024	2.6	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.
WOTS24	2024	1.3	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.
WOTS25	2024	4.9	Application of Dynamic Voltage Management capability at the upstream zone substation, reactive power network support.

8. Regulatory Investment Tests

The regulatory investment test for distribution (RIT-D) is an economic cost-benefit test used to assess and rank potential investments capable of meeting an identified need. The purpose of the RIT-D is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (the preferred option).

The RIT–D was initially introduced in March 2013, with Version 55 of NER, with a focus on augmentation expenditure, and was amended in September 2017 to include replacement expenditure planning.

8.1. RIT-D projects recently completed or in progress

This section provides details required by schedule 5.8 (e) in covering projects where the RIT-D has been completed in the preceding year or is in progress:

8.1.1. East Gippsland Electricity Supply RIT-D

On 15 September 2020, AusNet published Stage 1, the non-network options report, of the East Gippsland Electricity

Supply RIT-D. This RIT-D was to evaluate options to provide ongoing electrical supply capacity to customers in the East Gippsland supply area, with loading on the existing East Gippsland 66 kV network reaching its thermal and voltage limits.

Submissions to this non-network options report closed on 8 January 2021. After a review of the submissions, AusNet final decision was to close the RIT-D and continue to monitor peak demand growth on the East Gippsland 66 kV network as increases in new renewable energy generation connections continue. If deemed necessary, this project will undergo a reassessment through the RIT-D process.

8.1.2. REFCL Tranche 3 RIT-D

In March 2021, AusNet published a notice advising there is no credible non-network alternatives to Tranche 3 of the

REFCL installation projects. AusNet has since published the Final Project Assessment Report for Tranche 3 in May 2021.

8.1.3. CBTS Electricity Supply RIT-T

As outlined in Section 4.7.1, AusNet have published a RIT-T jointly with United Energy, and in consultation with AEMO, to assess options to mitigate the thermal loading risk on the Cranbourne Terminal Station (CBTS) 220/66 kV connection assets transformers. This RIT-T consultation had been completed in 2022, however, due to a material change in one of the inputs (option costs), Ausnet and United Energy have re-commenced the RIT-T with the Project Specifications Consultation Report (PSCR) being published in October 2024.

Further information on the CBTS Electricity Supply RIT-T is available on AusNet Services' website:

https://ausnetservices.com.au/About/Projects-and-Innovation/Regulatory-Investment-Test

8.1.4. Connection Enablement: Morwell East Area RIT-D

AusNet has received connection inquiries to connect a total of 1360 MW of renewable generation to the Morwell East sub-transmission (66 kV) network with 123.1 MW of generation currently connected. The Morwell East sub-transmission network was planned, built, and maintained to meet the demand in that area and is not strong enough to connect significant additional renewable generation.

AusNet commenced a Regulatory Investment Test for Distribution (RIT-D) in January 2024 to investigate and evaluate options to address the constraints in the MWTS East sub-transmission network which are restricting new renewable generation connections. AusNet evaluated a number of network options involving the augmentation of the Morwell

Terminal Station (MWTS) to Traralgon Zone Substation (TGN) 66kV subtransmission section as it was identified that this portion is a major bottleneck for connecting new generation to the Morwell East network.

The second report in the RIT-D process, the Draft Project Assessment Report (DPAR) was published in July 2024 and identified that the preferred option involves the augmentation of the MWTS – TGN No.1 and No.2 66kV lines to increase the capacity of both lines to equivalent of conductor rated at 19/4.75 All-Aluminium Conductor (AAC). AusNet expects to publish the final RIT-D report, the Final Project Assessment Report (FPAR), by December 2024.

Further information on the Connection Enablement: Morwell East RIT-D is available on AusNet Services' website:

https://ausnetservices.com.au/About/Projects-and-Innovation/Regulatory-Investment-Test

8.1.5. Connection Enablement: Morwell South Area RIT-D

AusNet has received connection inquiries to connect 860 MW of renewable generation to the Morwell South subtransmission (66 kV) network with 146.36MW of generation currently connected. The Morwell South sub-transmission network was planned, built, and maintained to meet the demand in that area and is not strong enough to connect significant additional renewable generation.

AusNet commenced a Regulatory Investment Test for Distribution (RIT-D) in January 2024 to investigate and evaluate options to address the constraints in the MWTS South sub-transmission network which are restricting new renewable generation connections. AusNet evaluated a number of network options involving the augmentation of the Morwell Terminal Station (MWTS) to Leongatha Zone Substation (LGA) 66kV subtransmission section as it was identified that this portion is a major bottleneck for connecting new generation to the Morwell South network.

The second report in the RIT-D process, the Draft Project Assessment Report (DPAR) was published in October 2024 and identified that the preferred option involves the augmentation of the MWTS – LGA No.2 and No.3 66kV lines to increase the capacity of both lines to equivalent of conductor rated at 37/3.75 All-Aluminium Conductor (AAC). AusNet expects to publish the final RIT-D report, the Final Project Assessment Report (FPAR), by December 2024.

Further information on the Connection Enablement: Morwell South RIT-D is available on AusNet Services' website:

https://ausnetservices.com.au/About/Projects-and-Innovation/Regulatory-Investment-Test

8.1.6. Connection Enablement: Wodonga – Barnawartha in North-Eastern Victoria RIT-T

AusNet has received a number of enquiries for a total of 390 MW of large-scale embedded generation to the Wodonga Terminal Station (WOTS) sub-transmission (66 kV) system with 60 MW of renewable generation currently connected. Of the connection enquiries, 370 MW is to connect into Barnawartha Zone Substation (BWA) and another 10 MW to Wodonga Zone Substation (WO) to BWA 66 kV feeder. The WO – BWA 66 kV feeder was originally planned to supply the small rural load connected to BWA ZSS. The summer rating of the existing line is limited to 64 MVA and the existing line cannot accommodate this additional generation. Further, WOTS would experience a significant reverse power flow with this proposed generation and the existing two transformers are not capable of handling this reverse power flow.

AusNet commenced a Regulatory Investment Test for Transmission (RIT-T) in January 2024 to investigate and evaluate options to address these constraints. Since the commissioning of a third transformer at WOTS would be a transmission augmentation project, a RIT-T was initiated to address the network augmentation needs of both transmission and distribution networks. The second report in the RIT-T process, the Project Assessment Draft Report (PADR) was published in July 2024 and identified that the preferred option involves the installation of a new WO-BWA 66kV line in parallel with the existing line using 37/3.75 All-Aluminium Conductor (AAC) and commissioning of the spare 330/66/22kV transformer at WOTS. AusNet expects to publish the final RIT-T report, the Project Assessment Conclusions Report (FPAR), by January 2025.

Further information on the Connection Enablement: Wodonga - Barnawartha in North-Eastern Victoria RIT-T is available on AusNet Services' website:

https://www.ausnetservices.com.au/projects-and-innovation/regulatory-investment-test

8.1.7. Overhead Manual Switch Replacement Program

AusNet's 22kV network comprises approximately 1400 pole mounted, ILJIN manufactured, 24kV manual SF6 gas load break switches. These manual switches enhance network reliability through minimising customer disruptions during planned or unplanned maintenance and network outages resulting from faults. Following an incident in October 2022, AusNet launched an internal investigation on ILJIN switch condition and placed a suspension on the operation and reuse of the switches displaying significant signs of corrosion. The investigation identified 480 existing ILJIN overhead switches adversely affected rendering them inoperable and unsafe.

Ausnet commenced a Regulatory Investment Test for Distribution (RIT-D) with the Final Project Assessment Report issued in February 2024. Further information on the Overhead Manual Switch Replacement Program is available on AusNet Services Website: https://www.ausnetservices.com.au/projects-and-innovation/regulatory-investment-test

8.1.8. YPS-MOE-WGL GroundWire Replacement

The condition of the overhead steel ground wire on the YPS-MOE-WGL 66kV line has deteriorated into a position that increases the risk to AusNet beyond an acceptable level. The over head steel ground wire has been in service since commissioning Victoria's first 132kV transmission line (now 66kV) and will now undergo a like for like replacement along 97 spans of the line.

AusNet commenced a Regulatory Investment Test for Distribution (RIT-D) with the Final Project Assesment Report issued in August 2024. Further information on the YPS-MOE-WGL is available on the AusNet Services Website: https://www.ausnetservices.com.au/projects-and-innovation/regulatory-investment-test

8.2. Future RIT-D projects

This section provides details required by schedule 5.8 (f) for each identified system limitation for which a DNSP has determined a RIT-D is required and is expected to commence in the next five-year period. In the five-year period, Ausnet expects to commence the RIT-Ds outlined in Table 31.

Table 31: Identified system limitations that are subject to the RIT-D

System Limitation	Proposed Project Commissioning	Estimated RIT-D Commencement	Section Reference
Cranbourne, CBTS-LYD-NRN-PHM-OFR-BWN-LLG-CLN 66 kV loop	To be determined	Q1 2025	6.1.1
East Gippsland Electricity Supply RIT-D, MWTS-TGN-SLE-MFA-BDSS-BDL-NLA-CNR 66 kV loop	To be determined	Q2 2025	6.1.4
Connection Enablement: Morwell East Stage 2 (MWTS-SLE-MFA)	To be determined	Q2 2025	N/A
Bairnsdale (BDL) Substation REFCL compliance maintained	2025	Q1 2025	9.18
Lilydale (LDL) REFCL compliance maintained	2025	Q1 2025	9.18
Capacity limitation of the Wollert area	2026-31	2025	9.15
Capacity limitation of the Pakenham South area	2026-31	2025	9.10
Supply security of Wonthaggi	2026-31	2025	4.7.3
REFCL 2026-31 Program of works	2026-31	2025	TBC
BN11 Express feeder	2026-31	2025	TBC
New 22kV feeders (SMR, WGL and WOTS)	2026-31	2025	TBC

KLO14 and KLO24 22kV feeders' capacity limitation	2026	Q1 2025	N/A
Newmerella Zone Substation asset condition risk	2028	June 2026	9.9
Thomastown Zone Substation asset condition risk	2028	Completed*	9.11
Traralgon Zone Substation asset condition risk	2026	Completed*	9.12
Watsonia Zone Substation asset condition risk	To be determined	To be determined	N/A
Mount Hotham underground cable condition risk	December 2022	Completed*	D.9
ILJIN Manual Switch Replacement-Stage 2	2025	Q1- 2025	N/A

**Staged project, RIT-D requirement in the next EDPR (27-31) to be assessed*

9. Completed, Committed and Planned Zone Substation Developments

This section provides details required by schedule 5.8 (b1), for individual assets planned to be retired, and for schedule 5.8 (g), being for projects within the forward planning period where investments of over $2 million in value are being implemented to address a refurbishment need, replacement need, or an urgent or unforeseen investment. Some planned or in progress projects have a cross-over with the twenty-two REFCL stations, as identified.

9.1. Bayswater Zone Substation rebuild

This project is currently in delivery stage to selectively retire and replace assets at the Bayswater Zone Substation (BWR). BWR was established in 1968 and contains outdoor bulk oil 22 kV circuit breakers and instrument transformers that were installed when the station was originally built. Some equipment panels have asbestos containing materials and live exposed wires at the rear of the secondary panels. The condition of these assets, as well as the high voltage transformer bushings, has deteriorated considerably and they now have an elevated risk of failure. These assets pose unacceptable safety, network security, environmental, and plant damage risks from possible destructive failure.

A project to address these issues, including the following key scope items, is expected to be completed by Sep 2025.

- Replace 22 kV outdoor switchgear with three new 22 kV indoor switchboards.
- Establish a new control room.
- Replace 22 kV and 66 kV instrument transformers.

This project will address asset failure risks due to deteriorated electrical equipment. The total project cost is approximately $17.7 million.

Alternative options considered include:

- Replace 22 kV equipment along with the No.2 66/22 kV transformer. Although this option would deliver higher benefits, these additional benefits are currently insufficient to economically justify the additional cost.
- Replace 22 kV equipment along with the No.1 and No.2 66/22 kV transformers. Although this option would deliver higher benefits, these additional benefits are currently insufficient to economically justify the additional cost.

9.2. Benalla Zone Substation rebuild and REFCL installation

In September 2023, AusNet completed the 22 kV outdoor switchgear and 66 kV bulk oil circuit breakers at Benalla Zone Substation (BN), including REFCL installation. The condition of these assets deteriorated considerably, and they had an elevated risk of failure. These assets posed unacceptable safety, network security, environmental, and plant damage risks from possible destructive failure and subsequent oil fires. There was also concern that the 22 kV switchgear was not capable to the higher REFCL voltages.

A project to address these issues, including the following key scope items have been recently completed:

- Replace outdoor bulk oil 66 kV circuit breakers with new outdoor 66 kV circuit breakers with estimated total cost of $10.7M and is expected to be implemented by June 2026
- Replace 22 kV outdoor switchgear with a new 22 kV indoor switchboard under REFCL program A remote REFCL at Violet Town was also required (this scope was delivered under a separate project).

This project addressed asset failure risks due to deteriorated electrical equipment, whilst ensuring integration with the implementation of REFCL technology (see section 13.5.3). The estimated total project cost was approximately $16.7 million.

9.3. Clyde North Zone Substation Capacity Augmentation

AusNet is planning to augment the supply capacity at Clyde North Zone Substation (CLN) to avoid overload of the existing two 66/22 kV 20/33 MVA transformers

A project to address the demand growth driven service level risk, including the following key scope items, is planned to be implemented by 2026:

- Install an additional (third) 66/22kV 20/33 MVA transformer.
- Install an additional (third) 22 kV indoor switchboard.
- Install associated protection and control works.

The design and procurement phase of this project has been completed. Anticipated service date is December 2025.

9.4. Kilmore South Zone Substation rebuild

The 22kV indoor switchgear at Kilmore South Zone Substation (ZSS) has degraded to a point where it poses unacceptable safety, network security, environmental and plant damage risks from possible destructive failure and loss of supply. Currently the in-service gear at KMS comprises of an indoor switch board and eight circuit breakers. Because of the condition of the indoor switchboard, this project proposes

- the removal of all the exiting switchgear and installation of one standard modular indoor switchboard.

The remaining assets at the station have been evaluated and do not pose a worthy risk to warrant replacement in the Kilmore South Zone Substation rebuild project.

The total capital cost of the project is estimated to be approximately $7 million and has a target completion date of November 2026.

9.5. Maffra Zone Substation rebuild

This project is currently in delivery stage to selectively retire and replace assets at the Maffra Zone Substation (MFA). MFA was established with two 10 MVA 66/22 kV transformers in 1960 and contains 66 kV minimum oil circuit breakers and oil filled current transformers that were installed when the station was built. A third transformer was installed in 1998. The condition of the circuit breakers and current transformers has deteriorated considerably, and they now have an elevated risk of failure. These assets pose unacceptable safety, network security, environmental and plant damage risksfrom possible destructive failure and subsequent oil fires. The condition of the transformers is also deteriorating; however, the replacement of these assets has been deferred to beyond 2026.

A project to address the switchgear condition is expected to be implemented by December 2024, and includes the following key scope items:

- Due to space constraints building new 66kV switchyard for construction of new 66kV ring bus on adjoining land and construction of new control building
- Replace outdoor minimum oil 66 kV circuit breakers with new outdoor 66 kV circuit breakers and adding one tie breaker between Transformer 2 and 3
- Replace outdoor 66 kV current transformers, 66kV voltage transformers, Two NCT's and 22kV capacitor bank.

This project will address asset failure risks due to deteriorated electrical equipment. The total project is approximately $29.0 million.

Alternative options considered include:

- Replace the two 10 MVA 66/22 kV transformers as well as the 66 kV equipment. This is much higher cost option and replacement of the existing C4 condition transformers is not currently economically justified.
- Replace the 66 kV outdoor switchgear with gas insulated switchgear, while maintaining the original 66/22 kV transformers. This is a high-cost option, due to the increased costs associated gas insulted switchgear, that would deliver less benefits than the proposed preferred option due to the remaining elevated failure risk associated with the two original transformers.
- Replace the 66 kV outdoor switchgear with new outdoor 66 kV switchgear and replace one of the two original 66/22 kV transformers. This is a lower cost option than the proposed preferred solution, but also has lower benefits due to the remaining elevated failure risk associated with the one original transformer that would not be replaced.

9.6. Newmerella Zone Substation rebuild

AusNet is planning to retire and replace assets at the Newmerella Zone Substation (NLA). NLA is a small remote zone substation containing two 5 MVA 66/22 kV transformers and a single outdoor 22 kV bus with outdoor 22 kV automatic circuit recloser (ACR) switches in place of traditional 22 kV circuit breaker switchgear. The condition of the two transformers and the 22 kV switchgear has deteriorated and they now have an elevated risk of failure. The assets pose unacceptable safety, network security, environmental and plant damage risks from possible destructive failure and subsequent oil fires and loss of supply.

A project to address these issues was planned for 2024 but has now been delayed to 2026 following more detailed assessment of the service level risk. Key scope items include:

- Replace the two 66/22 kV transformers
- Replace outdoor 22 kV circuit breakers with a new indoor 22 kV switchboard.
- Replace the six 66kV voltage transformers
-

This project will address the service level risk associated with the 66/22 kV transformers and 22 kV assets. The total project cost in 2024 real dollars is approximately $19.64 million ±30%.

Alternative options considered include:

- Replace only the existing outdoor 22 kV switchgear with a new indoor 22 kV switchboard. This is lower cost option but does not address the service level risk associated with the poor transfer condition.
- Replace the 66/22 transformers, while maintaining the existing outdoor 22 kV switchgear. This is medium cost option, due to the transformer replacements, however the benefits are limited due to the remaining elevated failure risk associated with the existing outdoor 22 kV switchgear.

9.7. Thomastown Zone Substation rebuild

This project is currently in delivery stage to selectively retire and replace assets at the Thomastown Zone Substation (TT). TT was established in the early 1950s and contains 66 kV and 22 kV bulk oil circuit breakers that were installed when the station was built. The condition of these circuit breakers has deteriorated considerably, and they now have an elevated risk of failure. These assets pose unacceptable safety, network security, environmental and plant damage risks from possible destructive failure.

A project to address these issues, includes the following key scope items, with scope being delivered partial deferment

- Replace outdoor bulk oil 22 kV circuit breakers with three new indoor 22 kV switchboards.
- Replace outdoor bulk oil 66 kV circuit breakers with new outdoor 66 kV circuit breakers.
- Replace the three 66kV/22kV transformers
- Associated protection and secondary system upgrades.

The preferred option is to complete this work in two stages. The scope of Stage 1 will replace two existing 66kV circuit breakers with associated works by February 2026 and Stage 2 will comprise the remaining scope of work. Stage 2 will be completed 5-10 years after Stage 1, with the works currently planned for completion in 2030.

The total capital cost of stage 1 is this option is $8.5 million $ million (real $2022). With stage 2 costing 27.39 million (real $2024).

9.8. Traralgon Zone Substation rebuild

AusNet is currently in the design and procurement stages of a project to selectively retire and replace assets at the Traralgon Zone Substation (TGN). Construction is planned to commence mid-2024. The project is expected to be completed by March 2026.

TGN was established with two 10/13.5 MVA 66/22 kV transformers and contains outdoor 66 kV and 22 kV oil filled switchgear that was installed when the station was built. A 20/33 MVA transformer, in addition to the two original 10/13.5 MVA transformers, was installed in 2013. The condition of the two original transformers and the 66 kV and 22 kV assets has deteriorated considerably, and they now have an elevated risk of failure. These assets pose unacceptable safety, network security, environmental and plant damage risks from possible destructive failure.

A project to address these issues, includes the following key scope with scope being investigated for partial deferment. The scope of items are:

- Replace the two 10/13.5 MVA 66/22 kV transformers with a single 20/33 MVA 66/22 kV transformer.
- Replace two 66 kV minimum oil circuit breakers.
- Replace outdoor 22 kV switchgear with a new indoor 22 kV switchboard.
- Replace the high voltage 66 kV transformer bushings.

The preferred option is to complete this work in two stages. Stage 1 will replace two existing 66kV circuit breakers and two 10/13.5 MVA 66/22 kV transformers with associated works by May 2026 and Stage 2 will comprise the remaining scope of work. Stage 2 will be completed 5-10 years after Stage 1, with the works currently planned for completion in 2030.

The total capital cost of this option is $16.5Mmillion (real $2024) for stage 1 and $11.74 million for stage 2 .

Alternative options considered include:

- Replace the 66 kV and 22 kV assets, while maintaining the existing transformers. This is a lower cost option than the proposed preferred solution but results in lower net economic benefits due to the remaining elevated failure risk associated with the two 66/22 kV transformers.
- Replace only the 22 kV assets, while maintaining the existing 66 kV assets and transformers. This is a much lower cost option than the proposed preferred solution but results in lower net economic benefits due to the remaining elevated failure risk associated with the 66 kV assets and the two 66/22 kV transformers.

9.9. Warragul Zone Substation rebuild

This project is currently in delivery stage to selectively retire and replace assets at the Warragul Zone Substation (WGL).. The condition of the original transformers and the 66 kV and 22 kV assets has deteriorated considerably, and they now have an elevated risk of failure. These assets pose unacceptable safety, network security, environmental and plant damage risks from possible destructive failure.

A project to address these issues is expected to be implemented by Dec 2027, and includes the following key scope items:

- Replace the four 10 MVA 66/22 kV transformers with two 20/33 MVA 66/22 kV transformers.
- Replace the No.2 capacitor bank.
- Install two new 66 kV circuit breakers to complete a fully switched ring bus.

This project will address the asset failure risks due to deteriorated electrical equipment and provide some additional capacity to supply the station load. The total project cost is approximately $20.3 million.

Alternative options considered include:

- Replace the four 10 MVA transformers, and the No.2 capacitor bank, with like-for-like assets. This is a high cost, due to the number of transformers to be installed, but delivers less benefits than the proposed preferred solution because four like-for-like transformers would provide a lower capacity than two 20/33 MVA transformers.
- Replace the No.2 capacitor bank and the four 10 MVA transformers with two 20/33 MVA transformers. This is a medium cost option but delivers lower net benefits due to the lack of redundancy from not having a complete 66 kV ring bus.

9.10. Watsonia Zone Substation rebuild

AusNet planned to selectively retire and replace assets at the Watsonia Zone Substation (WT). WT was established with two 66/22 kV transformers in the late 1950s, with a third transformer installed in 2010, and contains 22 kV bulk oil circuit breakers that were installed when the station was built.

The project had the following key scope items:

- Replace outdoor bulk oil 22 kV circuit breakers with new indoor 22 kV switchgear.
- Associated protection and secondary system upgrades.
- Alternative options considered include:
- Replace the two poor condition 66/22kV transformers

This project was to address 22kV switchgear and the 66/22 kV transformer failure risk. The total project cost was approximately $32.06 million ±30%. However, when preparing the RIT-D Draft Project Assessment Report (DPAR), the condition of the assets at Watsonia Zone Substation was reviewed using a new asset modelling tool. The conclusion of this review is that the condition of the assets does not warrant remedial action during the current planning period. Accordingly, AusNet didn't proceed with the remainder of the RIT-D process in relation to Watsonia Zone Substation. AusNet will recommence the RIT-D process when the asset condition at Watsonia Zone Substation warrants remedial action possibly in the next EDPR (2027-31).

9.11. Wollert New Zone Substation

Significant increases in loads have been observed in the Wollert area by AusNet.

The weighted POE demand forecasts are expected to exceed the effective N substation ratings at Kalkallo by the end of the next regulatory period, and the effective N-1 ratings at Doreen and Epping. A project to address the demand growth driven service level risk, including the following key scope items, is planned to be implemented after 2026:

- **Build a new Zone Substation at Wollert:** This involves augmenting the network by installing a new

  2x33MVA 66/22kV zone substation located close to the existing dual circuit 66 kV lines on the eastern edge of

  the Wollert precinct. This option relieves the loading at surrounding zone substations to reduce expected unserved energy and ensures there is sufficient capacity in Wollert to address the forecasted demand.

9.12. Wonthaggi Zone Substation Upgrade

- The town of Wonthaggi and surrounding areas including Inverloch and San Remo are predominately serviced by 66/22kV Wonthaggi (WGI) zone substation (ZS) established in the mid-1960s. Currently it has three, aged 10/13.5 MVA transformers in deteriorating conditions and seven 22kV feeders with outdoor 66kV and 22kV switchgear in an un-switched configuration.
-

By 2053, the population growth in Wonthaggi and surrounding areas including Inverloch and San Remo will ultimately result in approximately 4,500[14] new residential dwellings and 70 hectares of employment land comprise industrial and commercial developments - town centres, schools, community facilities, and future commercial spaces. When fully developed beyond 2053, it is expected that the development areas in Wonthaggi and surrounding areas, including Inverloch and San Remo, will result in a new load in the order of 44 MVA being added to AusNet Services' electricity network in South Gippsland.

To address this need the option is to replace 1 x 10/13.5 MVA Tx with 1 x 20/33 MVA Tx is being considered.

9.13. Pakenham South New Zone Substation

Significant increases in loads have been observed in the Pakenham South area by AusNet. State planning guidelines within the 'Victoria in Future' publication have forecasted significant future industrial development in the Pakenham South area. There are 1313 hectares of available industrial land supply of which 381 hectares, or 29% are zoned and occupied, 375 hectares, or 28,6% are zoned and vacant, and there is an additional 938 hectares of future supply that may ultimately be utilised.

By 2031 it is projected that approximately 128,000 additional jobs will be added to the Southern Region of Victoria.

Over half of the new jobs in the region are expected to be within the growth area municipalities of Casey and Cardinia. The industries that are expected to experience the strongest growth are: health care and social assistance; retail trade; manufacturing; construction; education and training.

The combined load at risk at four zone substations in the Officer South area - Clyde North, Officer, Pakenham, and Lang Lang is going to exceed acceptable limits.

A material level expected unserved energy (EUE) is calculated for this area. A project to address the demand growth driven service level risk, including the following key scope items, is planned to be implemented after 2026:

- **Build a new zone substation at Officer South**: This involves augmenting the network by installing a new 2x33MVA 66/22kV zone substation in the Pakenham South area. This relieves the loading at surrounding zone substations to reduce expected unserved energy and ensures there is sufficient capacity in the Pakenham South area to address forecast demand.

9.14. Further REFCL installation and geographic footprint

The installation and application of REFCL technology at twenty-two of AusNet zone substations was enacted on 1 May 2016 in the Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016by the Victorian Government. The Regulations are highly prescriptive and ambitious, detailing a seven-year implementation timeframe and performance standards that will be administered by Energy Safe Victoria.

The Bushfire Mitigation Regulations stipulate three tranches, with delivery due by May 2019, 2021 and 2023~~.~~

The twenty-two (22) REFCL zone substations are Kinglake (KLK), Woori Yallock (WYK), Kilmore South (KMS),

Wangaratta (WN), Rubicon A (RUBA), Barnawartha (BWA), Seymour (SMR), Myrtleford (MYT), Wonthaggi (WGI),

Benalla (BN), Ringwood North (RWN), Eltham (ELM), Ferntree Gully (FGY), Belgrave (BGE), Lilydale (LDL), Bairnsdale (BDL), Moe (MOE), Sale (SLE), Mansfield (MSD), Wodonga Terminal Station 22 kV switchyard (WOTS), Lang Lang (LLG), and Kalkallo (KLO).

Of the twenty-two (22) REFCL zone substation sites, all have achieved compliance. Due to reaching capacity and in order to maintain compliance two sites, Bairnsdale (BDL) and Lilydale (LDL) will require further augmentation next year. Remote REFCLs and 3rd GFN solutions are being considered. To maintain compliance in the next regulatory period further augmentation is required at Zone Substations SMR, WOTS, WYK and KLK

The Electricity Distribution Code (Version 9A), amended in August 2018, requires AusNet to identify all areas affected under a 'REFCL condition' in its DAPR. Figure 31 and Figure 32 below identify the geographic locations where a REFCL condition may be experienced.

[14] Source: 2019-04-18-Wonthaggi-Structure-Plan-and-Discussion-Paper-FINAL.PDF (basscoast.vic.gov.au)

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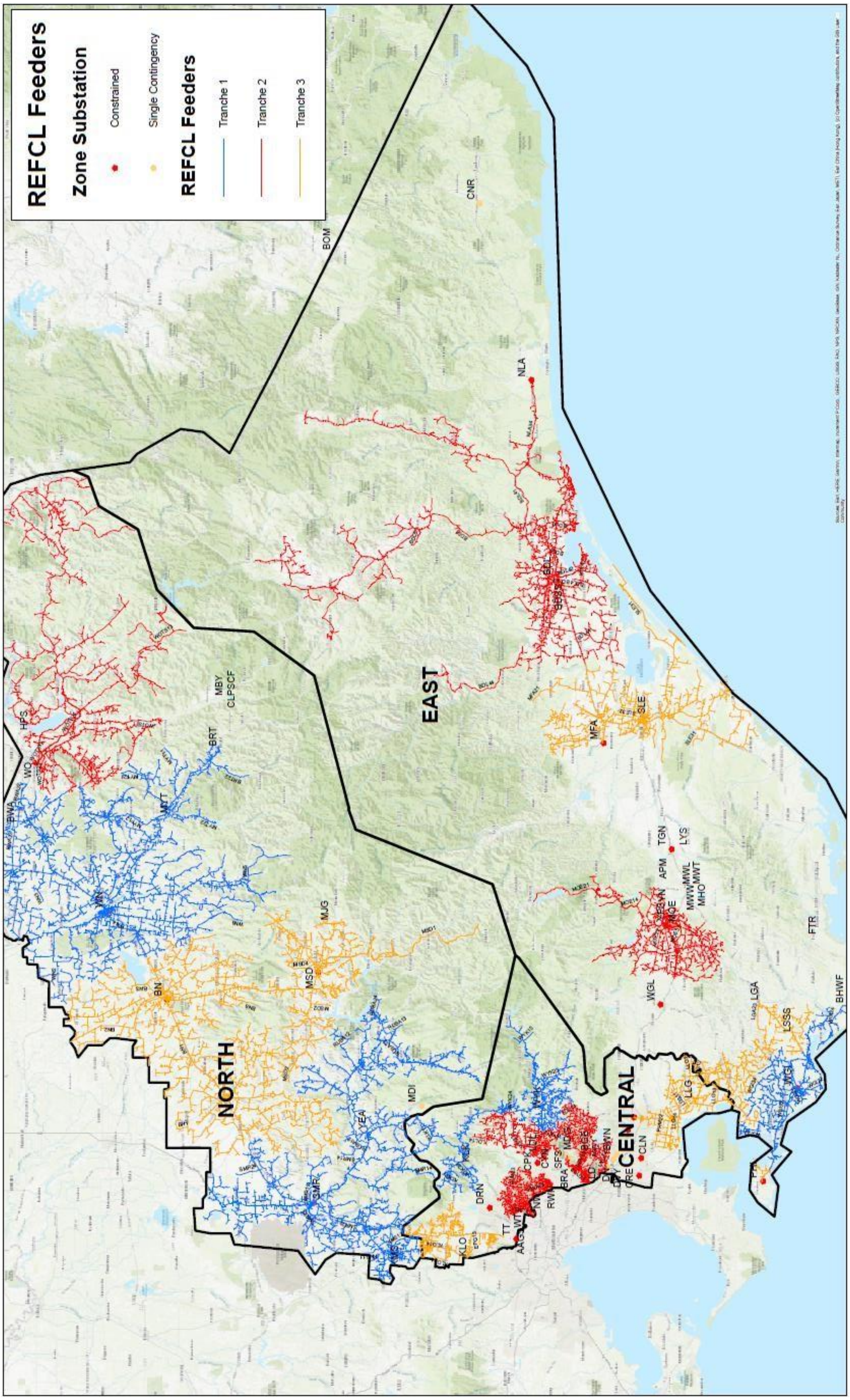

Figure 31: Feeders subject to a REFCL condition, by original tranche

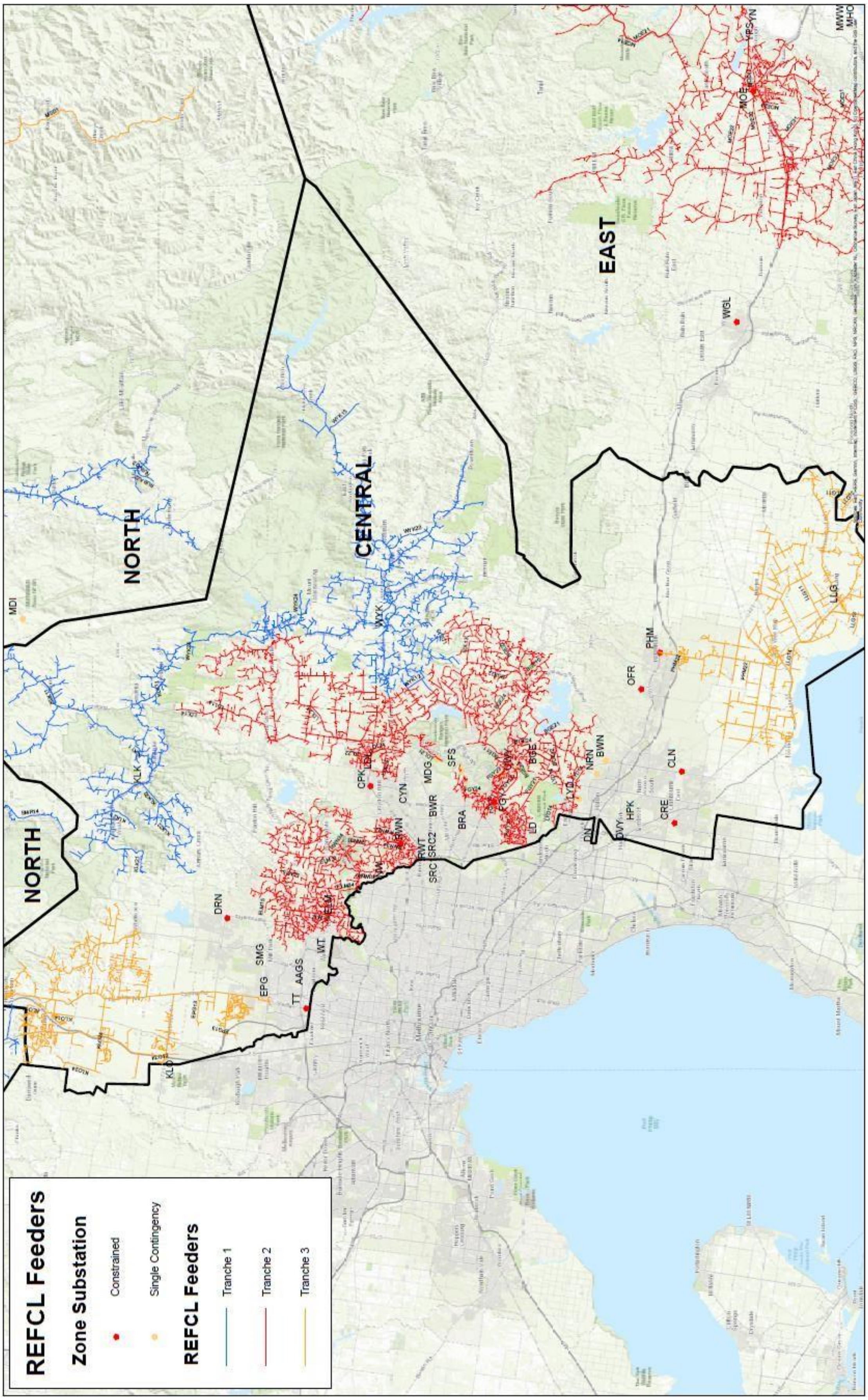

Figure 32: Feeders subject to a REFCL condition, by original tranche – Central region focus

10. Joint planning with the Transmission Network Service Provider

In accordance with clause 5.14 of the NER, AEMO and the Victorian DNSPs undertake joint planning to ensure the efficient development of the shared transmission and distribution networks and the transmission connection facilities. To formalise these arrangements, the parties have agreed a Memorandum of Understanding (MoU).

The MoU sets out a framework for cooperation and liaison between AEMO and the DNSPs regarding the joint planning of the shared network and connection assets in Victoria. The MoU sets out the approach to be applied by AEMO and the DNSPs in the assessment of options to address limitations in a distribution network where one of the options consists of investment in dual function assets or transmission investment, including connection assets and the shared transmission network. Under the MoU, the DNSPs and AEMO have agreed that, subject to the thresholds set out in the Rules, joint planning projects should be assessed by applying the RIT-T. The DNSPs also liaise regularly with AusNet Transmission Group, the majority owner of the Victorian transmission network, to coordinate their transmission connection augmentation plans with AusNet Transmission Group's asset renewal and replacement plans.

Clause 5.13.2(d) of the NER stipulates that a DNSP is not required to include in its DAPR information required in relation to transmission-distribution connection points if it is required to do so under jurisdictional electricity legislation (i.e., the Victorian EDCoP clause 19.3). The information for schedule 5.8 (h) regarding the results of any joint planning undertaken with the Transmission Network Service Provider (TNSP) has been included in the TCPR covering the period 2023-2032[15] and to avoid duplication is generally not repeated in this report. As required under schedule 5.8 (h), the TCPR contains a summary of the process and methodology used, a brief description of investments that have been planned (including the estimated capital costs of the investment and an estimate of the timing), and references to where additional information may be obtained.

As explained in section 4.7.1, AusNet and United Energy have re-commenced a RIT-T in relation to the thermal loading on the Cranbourne Terminal Station 220/66 kV connection asset transformers, with the Project Specifications Consultation Report (PSCR) being published in October 2024. In addition, AusNet and Jemena have identified load at risk at South Morang Terminal Station (SMTS) and AusNet Services will be initiating a Regulatory Investment Test for Transmission (RIT-T) to evaluate options for maintaining reliable power transformation services at SMTS. There is no other active joint planning work currently underway in relation to RIT-Ts.

Schedule 5.8(o) of the NER requires AusNet to report on analysis of known and potential interactions between control systems including a description of proposed actions to be undertaken to address any adverse interactions, considering the most recent general power system risk review undertaken by AEMO.

In July 2022, AEMO published its final report on the Power System Frequency Risk Review[16] which details the adverse impacts that increasing levels of distributed embedded generation has on the Under Frequency Load Shedding (UFLS) control scheme, causing minimum operational demand to fall below technically acceptable thresholds needed for the effective operation of the control scheme.

Under the NER, AEMO has primary responsibility for system security, however there is a general obligation on NSPs[17] to respond to AEMO's direction by developing and implementing solutions to mitigate grid security risks. In August 2021, AEMO issued a directive to Victorian NSPs to identify and implement measures to restore emergency underfrequency response to as close as possible to the level of 60% of underlying load[18] in all periods. In response, a working group was set up between the Victorian Department of Environment, Land, Water and Planning (DELWP), AEMO and the Victorian NSPs to collaboratively identify solutions to address emerging issues associated with minimum demand and the UFLS scheme in Victoria. This joint planning working group is expected to continue to be an ongoing collaborative exercise well into the next year.

AusNet is currently investigating options to install/enable under-frequency tripping relays with reverse flow blocking capability at 66kV sub-transmission lines within the AusNet distribution network.

[15] A copy of the 2023 Transmission Connection Planning Report and Terminal Station Demand Forecasts can be viewed at AusNet website: dapr.ausnetservices.com.au/ausnet_data/2023 TCPR.pdf.

[16] Power System Frequency Risk Review, AEMO, July 2022.

[17] Clause 4.3.3 of the NER.

[18] Clause 4.3.1(k) of the NER.

11. Joint planning with other Distribution Network Service Providers

This section provides details required by Schedule 5.8 (i) covering projects which AusNet is developing under joint distributor arrangements that are expected to commence in the next five-year period from 2023.

11.1. Distribution Network Service Providers' Joint Planning Process

AusNet engages with neighbouring DNSPs when required to plan for network upgrades where networks cross the boundaries between a neighbouring DNSP. AusNet has one 66 kV sub-transmission loop that is shared with United Energy and one 66 kV sub-transmission loop that is shared with Jemena. There are also some small sections of 22 kV feeders that provide energy to customers in a neighbouring DNSP and vice versa.

11.2. Jointly planned projects

Excluding joint planning of transmission connection assets, which are discussed in the TCPR, AusNet currently has no joint distribution planning project underway.

12. Performance of AusNet Network

This section highlights the performance of AusNet Distribution Network required under schedule 5.8 (j).

12.1. Reliability measures and standards in applicable regulatory instruments

The Distribution Use of System (DUoS) charges that AusNet levies to electricity retailers and some large customers are adjusted each year in accordance with price controls established by the Australian Energy Regulator (AER).

The Service Target Performance Incentive Scheme (STPIS) provides financial incentives for DNSP to maintain and improve service performance. Performance targets are set based on historical performances of the individual DNSP; thus, providing financial rewards for DNSPs beating their targets and financial penalties for failing to meet targets.

The STPIS applying to AusNet has two components:

- A reliability of supply component (S-Factor) which adjusts the revenue that a DNSP earns depending on reliability of supply.
- A Guaranteed Service Level (GSL) component which sets threshold levels of service for DNSPs to achieve and requires direct payments to customers who experience service worse than the predetermined level.

AusNet is also incentivised to maintain and improve customer service performance through the Customer Service Incentive Scheme (CSIS).

Table 32 shows the targets for the 2021-2026 regulatory control period.

Table 32: Period 2021-2026 performance targets for USAIDI, USAIFI and MAIFI

Measure	Feeder Class	2021-2026
Unplanned SAIDI	Urban	87.190
	Rural Short	195.160
	Rural Long	293.692
Unplanned SAIFI	Urban	0.891
	Rural Short	2.007
	Rural Long	2.628
Unplanned MAIFI	Urban	2.817
	Rural Short	5.657
	Rural Long	9.920

Source: FINAL DECISION AusNet Distribution Determination 2021 to 2026 Attachment 10 Service target performance incentive scheme, April 2021, pp10-6.

Notes:

- USAIDI (Unplanned System Average Interruption Duration Index, or the average minutes a customer is off supply each year resulting from unplanned outages with duration greater than three minutes).

- USAIFI (Unplanned System Average Interruption Frequency Index, or the average number of times a customer is off supply each year resulting from unplanned outages with duration greater than three minutes).
- MAIFI (Momentary Average Interruption Frequency Index or the average number of times a customer is off supply for less than three minutes each year).
- Call centre performance (the percentage of fault calls progressing to an operator that are answered within 30 seconds).
- For the 2021-2026 regulatory control period, AusNet have opted to apply a Customer Service Incentive Scheme (CSIS) rather than the STPIS telephone answering parameter, however it is proposed that AusNet continue to report on the telephone answering parameter for transparency purposes.

Table 33 summarises the supply restoration and low reliability payments schemes applicable in the current (2021 to 2026) EDPR period.

Table 33: GSL Supply Restoration and Low Reliability Payments – 2021 to 2026

Measure	Condition	Amount
Duration	Where the customer experiences more than 18 hours of unplanned sustained interruptions per year; or	$ 130
	Where the customer experiences more than 30 hours of unplanned sustained interruptions per year; or	$ 190
	Where the customer experiences more than 60 hours of unplanned sustained interruptions per year;	$ 380
Number of Sustained Outages	Where the customer experiences more than 8 unplanned sustained interruptions per year; or	$ 130
	Where the customer experiences more than 12 unplanned sustained interruptions per year; or	$ 190
	Where the customer experiences more than 20 unplanned sustained interruptions per year	$ 380
Number of Momentary Outages	Where the customer experiences more than 24 momentary interruptions per year; or	$ 40
	Where the customer experiences more than 36 momentary interruptions per year.	$ 50
Major Event Day	Where the customer experiences an unplanned sustained interruption of more than 12 hours on a major event day.	$ 90

Source: Electricity Distribution Code review – customer service standards, Final decision, 16 November 2020, pp. 45-46

12.1.1. Exclusion Criteria

Section 3.3 of the revised Electricity Distribution Network Service Providers – STPIS Nov 2018 outlines the exemption criteria applicable in the EDPR period 2016-2020. The same set of criteria is applicable to the EDPR period 2021-2026. Events that fall in any of the following conditions may be excluded in calculating the revenue increment or decrement as well as annual performance under the STPIS scheme.

Exclusions include:

(a) The following events may be excluded when calculating the revenue increment or decrement under the scheme when an interruption on the DNPS's distribution network has not already occurred or is concurrently occurring at the same time:

- Load shedding due to a generation shortfall.
- Automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition.
- Load shedding at the direction of AEMO or a system operator.
- Load interruptions caused by a failure of the shared transmission network.
- Load interruptions caused by a failure of transmission connection assets except where the interruptions were due to:
  - (a) actions, or inactions, of the DNSP that are inconsistent with good industry practice; or
  - (b) inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning.

  Example: a DNSP omits to suppress back-up earth fault (BUEF) protection when undertaking network switching operation that results in momentary paralleling of supplies from two different terminal stations, where this is inconsistent with the standard practice.
- Load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.
- Load interruptions caused or extended by a direction from state or federal emergency services, provided that a fault in, or the operation of, the network did not cause, in whole or part, the event giving rise to the direction.

(b) An event may also be excluded where daily unplanned SAIDI for the DNSP's distribution network exceeds the major event day (MED) boundary.

In addition to the above set of criteria, the AER considers that avoidable supply interruptions due to the suppression of the auto-recloser system under an approved Electricity Safety Management Scheme would meet the exclusion criteria under clause 3.3(a)(7) of the STPIS.

12.2. Performance against reliability measures and standards

Table 34 summarises the reliability performance of the electricity distribution network for the EDPR FY22-FY26 to date. Total performances with and without exemptions are shown in Table 34 along with individual targets, which include exemptions, for each feeder category.

Table 34 Network Performance Summary

Measure	Feeder Class	EDPR Period 2021/22 – 2025/26					
		5 YR TARGET	FY22/23		FY23/24		FY2/25
			TOTAL	NET[23]	TOTAL	NET[23]	NET[19]
Unplanned SAIDI	Urban	87.190	84.097	75.525	392.035	110.388	81.530
	Rural Short	195.160	244.405	195.819	1091.926	169.571	223.000
	Rural Long	293.692	413.267	351.194	1605.178	281.800	368.242
Unplanned SAIFI	Urban	0.891	0.669	0.621	1.438	0.984	0.771
	Rural Short	2.007	1.554	1.380	2.189	1.245	1.927
	Rural Long	2.628	2.629	2.307	3.917	2.020	2.658
Unplanned MAIFI	Urban	2.817	3.089	3.060	3.452	2.949	2.707
	Rural Short	5.657	4.997	4.833	4.799	4.220	5.747
	Rural Long	9.920	9.799	9.581	7.610	6.534	9.780

FY24 is the third regulatory year of the current price reset period in financial (July-June) cycle. After removing exclusions, the FY-2023/24 performances for SAIDI, SAIFI and MAIFI were favourable in rural feeder categories. Urban connected customers experienced worse that target performances from SAIDI, SAIFI and MAIFI even after removing exclusions. During the year, three MEDs were recorded with a combined impact of ~673 USAIDI minutes. There was one transmission event at the Cranbourne Terminal Station (CBTS) caused by a human error. A total of 16 separate unplanned incidents accumulated ~3.88 USAIDI minutes from asset failures caused by REFCL pre-conditioning or compliance testings. Also, there were 188 unplanned incidents that accumulated 20.72 SAUIDI minutes as a result of the mandatory operation or REFCLs at increased sensitivity.

These STPIS exclusions are summarised in Table 35.

Table 35: Summary of exclusions

Event Description	Exclusion Criteria	USAIDI, Minutes				
		CY20	HY1-2021	FY22	FY23	FY24
Load shedding - generation shortfall	3.3(a)(2)	-	-	-	-	-
Load shedding - under frequency	3.3(a)(3)	-	-	-	-	-

[19] End of year forecast, after removing exclusions, based on year-to-date performance as at 31 October 2024.

Load shedding - AEMO	3.3(a)(4)	0.02	-	-		
Transmission - shared network	3.3(a)(5)	-	-	-		
Transmission - asset failure	3.3(a)(6)	1.55	0.37	-	1.10	
Imposed obligation by legislation	3.3(a)(7)	5.46	0.65	7.21	24.80	
Imposed restrictions by authorities	3.3(a)(8)	-	-	-		

Table 36 summarises the supply restoration and low reliability GSL performance for FY22-23.

Table 36: Summary of Reliability of Supply GSL

AusNet Measure	Supply Interruption Condition	Payment	Number of eligible customers	Amount
Duration of Interruption	>18 hrs.	$130	21,974	$2,856,620
	>30 hrs.	$190	7,093	$1,347,670
	>60 hrs.	$380	1,437	$546,060
Number of Sustained Outages	> 8 interruptions	$130	6,036	$784,680
	> 12 interruptions	$190	551	$104,690
	> 20 interruptions	$380	3	$1,140
Number of Momentary Outages	> 24 interruptions	$40	5,860	$234,400
	> 36 interruptions	$50	2,398	$119,900
Interruption	Major Event Day	$90	225,971	$20,337,390
TOTAL			271,323	$26,332,550

12.2.1. Inadequately Served Customers

On 5 September 2014, the Australian Energy Market Commission (AEMC) released the final report on the **Review of Distribution Reliability Measures**. A chapter was dedicated discussing the factors "the AER should have regard to when developing a method for assessing the trade-offs between reliability and cost in those areas that experience lower levels of reliability of electricity supply". This report recognises that reliability experienced by some customers in a distribution network can be materially lower than that experienced by many (i.e. average) of the other customers in that network.

On 14 November 2018, the Australian Energy Regulator (AER) released a report on **Distribution Reliability Measures Guideline**. Prior to this release, the AER and state regulators define how reliability should be measured making it hard to compare performances across Australia. The AEMC implemented a rule change that required the development of common definitions and measurements for distribution reliability in the National Electricity Market (NEM).

In the AERs new guideline, the **Inadequate level of service customer** was defined as customer experiencing greater than 4 times the Network average for unplanned SAIDI on a three-year rolling average basis compared with a network average customer. Consequently, the AER now requires DNSPs to report **Inadequately Served Customers** in the annual RIN submissions.

Table 37: FY23-24 Inadequately served customer statistics

INADEQUATELY SERVED CUSTOMERS		
		Number
A - SAIDI VALUES		
Threshold SAIDI value for inadequately served customers	SAIDI	2,159
Average unplanned SAIDI of inadequately served customers	SAIDI	2,941
Highest unplanned SAIDI of inadequately served customers	SAIDI	5,210
B - SAIFI VALUES		
Average unplanned SAIFI of inadequately served customers	SAIFI	3.61
Highest unplanned SAIFI of inadequately served customers	SAIFI	7.50
C - TOP 5 FEEDERS WITH MOST INADEQUATELY SERVED CUSTOMERS		
SAIDI VALUE		
BGE22		5,210
BGE23		3,630
BGE13		3,522
FTR12		3,244
LGA11		3,184
SAIFI VALUE		
BGE22		5.69
BGE23		3.03
BGE13		4.13
FTR12		4.30
LGA11		2.64
NUMBER OF INADQUATELY SERVED CUSTOMERS		
BGE22		3,357

BGE23		2,350
BGE13		1,618
FTR12		1,649
LGA11		1,728

12.3. Corrective Actions – Reliability

The following subsections detail corrective actions that have been taken in relation to reliability and quality of supply.

12.3.1. Corrective Action – Reliability

AusNet is focusing on improving the distribution network's reliability performance by systematically reviewing poorly performing segments and investing in technology that automatically reconfigures the affected network to minimise the number of customers affected by outages.

AusNet will continue to monitor the reliability performance and take appropriate actions to outperform the targets. These include installing additional switches, fuses, ACRs, vegetation management, animal proofing and protection coordination improvements.

12.3.2. Performance Evaluation Method

When evaluating reliability performance, it is important to use a methodology that employs statistical analysis of long run trends rather than a year-to-year or year-to-target comparison. This avoids implementing an investment strategy that reacts to recent events, rather than a predictive strategy focussed on closing the gap between current performance and future targets. Accordingly, AusNet:

- Normalises the impact of external factors, such as weather, on annual performance.
- Uses weighted five-year performance to identify underperforming circuits.
- Employs statistical mean and standard deviation to analyse the significance of variations in performance indicators.
- Internally reports daily reliability performance against targets, for both unplanned and planned outages.
- Conducts regular meeting between the reliability improvement team, to discuss improvement measures for current reliability issues.
- Closely monitors low reliability feeders.
- Participates in benchmarking study to identify the strengths and the weaknesses of regional areas when compared to best practice.
- Assesses in detail how the network performed during storm events to maintain trending data and determine opportunities future asset programs.
- Monitors repetitive faults in the network monthly to establish emerging problems.
- Monitors performance of distribution feeders for which new initiatives have been implemented to identify their effectiveness and if opportunities exist to extend these programs.
- Undertakes analysis of any event that contributed 0.3 USAIFI or more and any large event that contributed 2.0 USAIDI minutes or more, to determine improvement opportunities in terms of AusNet response to the outage events from both an operational and strategic perspective.

12.4. Quality of supply standards

The quality of supply standards that apply to Victorian DNSPs are stipulated in the EDCoP published by the Essential

Services Commission (ESC), Victoria. The Electricity Distribution License issued by the ESC to AusNet Electricity Services Pty Ltd requires compliance with the EDCoP. The EDCoP provides standards and guidelines in relation to following quality of supply parameters.

AusNet is committed to maintaining power supply quality within the limits specified in the above code and relevant standards. The following power quality parameters are discussed in this section:

- Voltage standards
- Power factor
- Harmonics
- Inductive interference
- Load balancing (Negative sequence voltage)
- Flicker

12.4.1. Voltage Standards

The EDCoP specifies the voltage levels that must be maintained at the meter or point of supply to the customer's electrical installation. These levels are:

- 230 V (meter)
- 400 V (meter)
- 460 V (meter)
- 6.6 kV (point of supply)
- 11 kV (point of supply)
- 22 kV (point of supply)
- 66 kV (point of supply).

The EDCoP clause 20.4 specifies the Standard Voltage Variations limits at each voltage level. These levels are specified in Table 38 below.

Table 38: Standard Nominal Voltage Variations

	Voltage Level in kV	Standard Nominal Voltage Variations			
		Steady State	**Less than 1 minute**	**Less than 10 seconds**	**Impulse Voltage**
1	< 1	AS 61000.3 .100*			6 kV peak
2		+13 % -10 %	+13 % -10 %	Phase to Earth +50%-100% Phase to Phase +20%-100%	
3	1-6.6	± 6 % (± 10 % Rural Areas)	± 10 %	Phase to Earth +80%-100% Phase to Phase +20%-100%	60 kV peak
4	11				95 kV peak
5	22				150 kV peak
	Voltage Level in kV	**Standard Nominal Voltage Variations**			

		Steady State	Less than 1 minute	Less than 10 seconds	Impulse Voltage
6	66	± 10%	± 15%	Phase to Earth +50%-100% Phase to Phase +20%-100%	325 kV peak

Notes:

* When examining network-wide compliance, functional compliance is met if the limits in Table 2 of AS 61000.3.100 (up to 1% of measurements below 216 V and up to 1% of measurements above 253 V) are maintained across at least 95% of a distributor's customers.

** Row 2 values (steady state, less than 1 minute, and less than 10 seconds) define the circumstances in which a distributor must compensate a person whose property is damaged due to voltage variations according to clause 20.4.8. Schedule 3 of the EDCoP illustrates this further.

The Phase to Earth voltage variations in Table 38above does not apply during the period in which a REFCL condition is experienced on the distribution system (including when a REFCL condition arises from the commissioning and testing of a REFCL). Under these conditions the Phase-to-Phase voltage variations in Table 39 apply to that part of the 22kV distribution system experiencing the REFCL condition.

Table 39: REFCL Condition Nominal Voltage Variations

Voltage Level in kV	Phase To Phase Nominal Voltage Variations			
	Steady State	Less than 1 minute	Less than 10 seconds	Impulse Voltage
22	± 6% (± 10% rural areas)	± 10%	Phase to Phase +20%-100%	150kV peak

The Australian Standard AS 61000.3.100-2011 is also used as appropriate for assessment of steady state voltage limits.

Electricity Safety (Bushfire Mitigation) Regulations 2013[20] introduced on 1 May 2016 require AusNet to install Rapid Earth Fault Current Limiter (REFCL) devices. These devices are to be deployed in high fire risk areas prior to 1 May 2023.

REFCLs reduce energy release in powerline earth faults (fallen wire, tree touching wire, etc.) by rapidly displacing network voltages to bring the voltage on the faulted conductor close to zero. On a 22kV network, REFCL response to an earth fault will very quickly reduce the voltage on the faulted conductor from around 12,700 volts to less than 250 volts. This displacement necessarily causes the phase-to-earth voltages on two un-faulted conductors to increases to 173% (i.e., the square root of three) of their pre-fault level.

12.4.2. Power Factor

The EDCoP clause 20.5.5 requires a customer to ensure that the customer's demand for reactive power does not exceed specified limits. These limits are shown in Table 40.

[20] Electricity Safety (Bushfire Mitigation) Regulation 2013, Version 004, 05/01/2016

Table 40: Power Factor Limits

Supply Voltage in kV	Power Factor Range for Customer Maximum Demand and Voltage					
	Up to 100 kVA		Between 100 kVA-2 MVA		Over 2 MVA	
	Minimum Lagging	Minimum Leading	Minimum Lagging	Minimum Leading	Minimum Lagging	Minimum Leading
<6.6	0.8	0.8	0.8	0.8	0.85	0.85
6.6 11 22	0.8	0.8	0.85	0.85	0.9	0.9
66	0.85	0.85	0.9	0.9	0.95	0.98

A customer must use best endeavours to keep the power factor of its electrical installation within the relevant range set out in Table 40. AusNet supply policy and connection agreements stipulate these requirements and therefore power factor limits are maintained at most connection points. AusNet uses tariffs on reactive power for its large customers to incentivise compliance.

12.4.3. Harmonics

The EDCoP clause 20.6.3, requires the distributor to ensure that the harmonic levels in the voltage at point of common coupling (PCC) nearest to a customer's point of supply comply with the levels specified by the system standards set out in Schedule 5.1a, clause S5.1a.6 of the NER.

Further, subject to clause 20.6.1, a distributor must comply with the system standards set out in Schedule 5.1a, clause S5.1a.6 of the NER, particularly establishment of the 'planning level' by the distributor.

As per the existing EDC, a customer must keep the harmonic currents below the limits specified in Table 41 and otherwise comply at its nearest PCC with IEEE standard 519-1992 "Recommended practices and Requirements for Harmonic Control in Electrical Power Systems". The joint Australian/New Zealand Technical Report TR IEC

61000.3.6.2012 will also be used as appropriate for the allocation of voltage harmonic limits to disturbing loads or generators.

Table 41: Current Harmonic Distortion Limits

Isc/IL	Maximum Harmonics Current Distortion in Precent of IL Individual harmonics Order 'h' (Odd Harmonics)					THD
	<11	11≤h<17	17≤h<23	23≤h<35	35≤h	
<20	4.0%	2.0%	1.5%	0.6%	0.3%	5.0%
20<50	7.0%	3.5%	2.5%	1.0%	0.5%	8.0%
50<100	10.0%	4.5%	4.0%	1.5%	0.7%	12.0%
100<1000	12.0%	5.5%	5.0%	2.0%	1.0%	15.0%
>1000	15.0%	7.0%	6.0%	2.5%	1.4%	20.0%

Notes:

- Even harmonics are limited to 25% of the odd harmonics listed above.
- Current distortions that result in a DC offset, e.g., half-wave converters, are not allowed.
- *All power generation equipment is limited to these values of current distortion, regardless of actual ISC/IL.
- Isc = maximum short-circuit current at point of common coupling.
- IL = maximum demand load current (fundamental frequency component) at point of common coupling.

AusNet maintains harmonic voltages within limits at most of its supply points. Harmonic voltages are known to have deviated from the allowable limits at several locations in the network. These instances were observed from analysis of metered data and from customer enquiries. Where harmonic voltage is suspected to be outside limits, it is investigated, and corrective measures are developed.

12.4.4. Inductive Interference

The EDCoP clause 20.7 requires the distributor to ensure that inductive interference caused by its distribution system is within the limits specified in AS 2344-2016.

AusNet design standards avoid generation of radio frequency interference (RFI) or Television interference (TVI) on the network. This is mainly achieved by type tested equipment and suitably designed components. In addition, routine cyclic inspections and maintenance procedures ensure that the network is maintained in a good condition to ensure RFI & TVI is not generated or limited to levels that will not affect customers.

12.4.5. Load Unbalance (Negative Sequence Voltages)

The EDCoP clause 20.8.1 requires the distributor to maintain the negative sequence voltage at the PCC to a customer's three-phase electrical installation in accordance with the system standard in Schedule 5.1a, clause S5.1a.7 of the NER.

12.4.6. Flicker

The EDCoP clause 20.10 requires the distributor to maintain voltage fluctuation at the point of common coupling at a level no greater than the levels specified in accordance with the system standards set out in Schedule 5.1a, clause S5.1a.5 of the NER.

Appropriate flicker allowances are given to customers with disturbing loads prior to supply connection approval.

These allowances are given based on the aforementioned Standards.

There have been no recent flicker related complaints.

12.5. Performance against quality of supply measures and standards

Outlined in the subsections below is a summary of AusNet performance against the measures and standards.

12.5.1. Network Performance – Quality of Supply

As per the EDCoP clause 20.4.7, AusNet monitors and records steady state voltages and voltage variations. The recorded quality of supply performance is reported to the Australian Energy Regulator which publishes it in the form of the 'Victorian Electricity Distribution Businesses – Comparative Performance Report'[21]. Other quality of supply issues is dealt with on an as needs basis according to the EDCoP Clause 25.3.1. Further information on how AusNet manages Quality of Supply issues can be found in Section 12.4. Table 42 shows the network quality of supply performance statistics from the past five regulatory periods.

[21] A copy of the report can be found at the Australian Energy Regulator's website: http://www.aer.gov.au/node/483

Table 42: Summary of Voltage Variations

Quality of Supply - Voltage Variation	CY19	CY20	HY1-2021	FY22	FY23	FY24
Voltage variations - steady state (zone sub)	2,949	1,080	641	1,309	3,312	2,038
Voltage variations - one minute (zone sub)	134	997	1,354	3,348	2,258	1,885
Voltage variations - 10 seconds (zone sub) Min<0.7	965	885	540	1,505	1,423	1,516
Voltage variations - 10 seconds (zone sub) Min<0.8	1,537	1,314	740	2,274	2,227	2,429
Voltage variations - 10 seconds (zone sub) Min<0.9	5,679	2,676	1,478	4,562	5,022	6,621
Voltage variations - steady state (feeder)	12,542	12,334	364	391	287	358
Voltage variations - % zone subs monitored	98%	100%	100%	100%	100%	100%
Voltage variations - % feeders monitored	98%	100%	100%	96%	98%	98%

Quality of supply monitoring is becoming increasingly important given the technology shift occurring in the industry, and the corrective action taken or planned to maintain quality of supply within the EDCoP limits are described in the following sections.

12.5.2. Network Performance – Voltage Level Reporting

In accordance with clause 19.4.1(e) of the EDCoP, AusNet is required to publish annual voltage level reporting information in the detailed in Schedule 2 of the EDCoP. The aggregated 10-minute-averaged voltage data identified in Table 7 of Schedule 2 of the EDCoP for each calendar year for the past 5 years are published in our website.

12.5.3. Network Performance – Voltage Level Reporting Methodology

The methodology used to produce the voltage data and other categories of information is described herein:

- The voltage data published in the CSV file is the 10-minute averaged voltage data over 3 months of the aggregated AMI population of each Voltage Control Section (VCS). The relevant 3-month periods (starting the first Sunday of the month) are as follows:
  - 1 December – 28 (or 29) February (depending on the year)
  - 1 March – 31 May
  - 1 June – 31 August
  - 1 September – 30 November

- The voltage data are populated for four different time bands for each Voltage Control Section over the 3month period. The time-blocks defined in Table 6 of Schedule 1 include the start and end time is inclusive of the hour, which will double count the transition hour. For aggregation of data, the time blocks indicated below are considered to finish one minute before end time (e.g., 10:00-16:00 is considered to be 10:00-15:59).
  - 10:00 – 16:00
  - 16:00 – 22:00
  - 22:00 – 04:00
  - 04:00 – 10:00
- Schedule 2 of the EDCoP defines a voltage control section (VCS) as any device or equipment, which manages the feeder voltage, starting from the zone substation on-line tap changer. Therefore, each feeder comprises of voltage control sections starting from the distribution zone substation and where applicable VCS sections are identified downstream of line voltage regulators and SWER isolating transformers.
- AusNet receives 5-minute instantaneous voltage data from AMI meters. The existing 5-minute instantaneous voltage data (from AusNet Power Quality dataset) are used to derive the averaged voltage data over each 3-month period for each time block for each voltage-controlled section. This method is used because a similar outcome is achieved by averaging the 5-minute instantaneous data as calculating the 10-minute averaged voltage data for each voltage control section over the specified time blocks on 3-month periods.
- In addition to voltage data, standing data on feeders are provided as specified in Schedule 2 of the EDCoP. The standing data used in the voltage report comes from different sources; some are historical (time-bound) and others are current. Therefore, some of the standing data represents the state of the network as at present and some data being correct as of the historical analysis date. The table below details whether a column in the resultant dataset is time-bound or as-is. The customer counts (and customers with small embedded generation) are based on unique NMIs. As the source of customer counts is joined by the analysis date, the counts reflect what it was at the analysis dates.
- The geographical location details of voltage control devices (Column IDs: VCS_Latitude and VCS_Longitude) and type of VCS devices (Column ID: VCS_Type) are also included in the voltage report.

Table 43: Standing data details

Column ID	Column Description	Time-bound (historic) data	As-at (current) data
ZONE_SUB	Zone Substation		✓
FEEDER	Feeder		✓
FEEDER_CLASS	Feeder class (urban, short rural or long rural)		✓
VCS_NAME	Name of VCS		✓
BUSINESS_ID	Detailed name of VCS		✓
AMI_CUSTOMERS	Customers with AMI	✓	
AMI_CUSTS_WITH_EG	AMI customers with embedded generation	✓	

PCT_AMI_CUSTS_WITH_EG	Percentage of AMI customers with embedded generation	✓	

12.6. Corrective Action – Quality of Supply

At a high level, AusNet aims to maintain sub-transmission network voltages (66 kV) within the EDCoP limits utilising the methods described below:

- Terminal Station transformer on load tap changer (OLTC)
- Terminal Station reactive support
- Line voltage regulators (66 kV)
- Establishing optimum 66 kV voltage set points at each terminal station.
- AusNet the terminal station secondary (i.e. 66 kV) bus voltages were reviewed during 2015 and the setting points were informed to the AEMO as part of the annual reporting requirement. There were no changes from the previous year at the eleven connection points.

At a high level, AusNet aims to maintain distribution feeder voltages (22 kV) within the EDCoP limits utilising the methods described below:

- Zone Substations on load tap change (OLTC)
- Zone substations reactive support
- Line voltage regulators (22 kV)
- Pole mounted 22 kV capacitor banks (typically 900 kVAR at a location)
- Establishing optimum 22 kV voltage set points at each zone substation.
- Distribution feeder voltages are reviewed on an ongoing basis and where necessary adjustments are made to existing line voltage regulators, feeder configurations, capacitors and zone substation voltage set points. The secondary bus voltages (i.e., 22 kV) at a number of zone substations were lowered during the year to cater for increased penetration of solar photovoltaic arrays. AusNet utilises voltage profiles captured by AMI meters to implement optimum distribution feeder voltages.
- AusNet low voltage network voltages (230/400 V) are maintained within the EDCoP limits utilising the methods described below.
- Distribution transformer off-load tap changes
- Upgrading or constructing new distribution substations
- Load balancing
- Low Voltage line augmentation

12.6.1. Voltage compliance corrective action

With the increased penetration of distributed generation, such as solar PV, increasing network voltages and voltage operating bands, AusNet has increased its voltage monitoring capabilities, utilising AMI data, and developed proactive programs to improve voltage compliance and distributed energy resources (DER) integration. As part of voltage management action plan, identified ZSS's with highest voltage constraints(usually higher breach) based on historical data and revised the VRR settings to improve overall network functional compliance. In addition to that the voltage monitoring tool and the three key voltage management and DER integration programs are outlined in the following sections

12.6.1.1. Utilisation of AMI data in voltage compliance monitoring and corrective action

In addition to the above traditional methods, AusNet has developed a tool, known as Explore, that uses AMI data and network analytics to monitor the level of voltage compliance within AusNet distribution network. Explore provides an up-to-date view of the level of voltage compliance and stores historical data to give a view of how voltage compliance has changed over time.

The target for 'functional compliance' to the Australian Standard, AS 61000.3.100, is to have less than 5% of customers experiencing voltages outside the 216-253 Volts target range on the low voltage network. Figure 33 shows how the level of voltage compliance improved between January 2014 and December 2024, with overvoltage (high breach) non-compliance reducing from approximately 30% to 5%. It also shows that compliance with the undervoltage (low breach) limits has been mostly maintained.

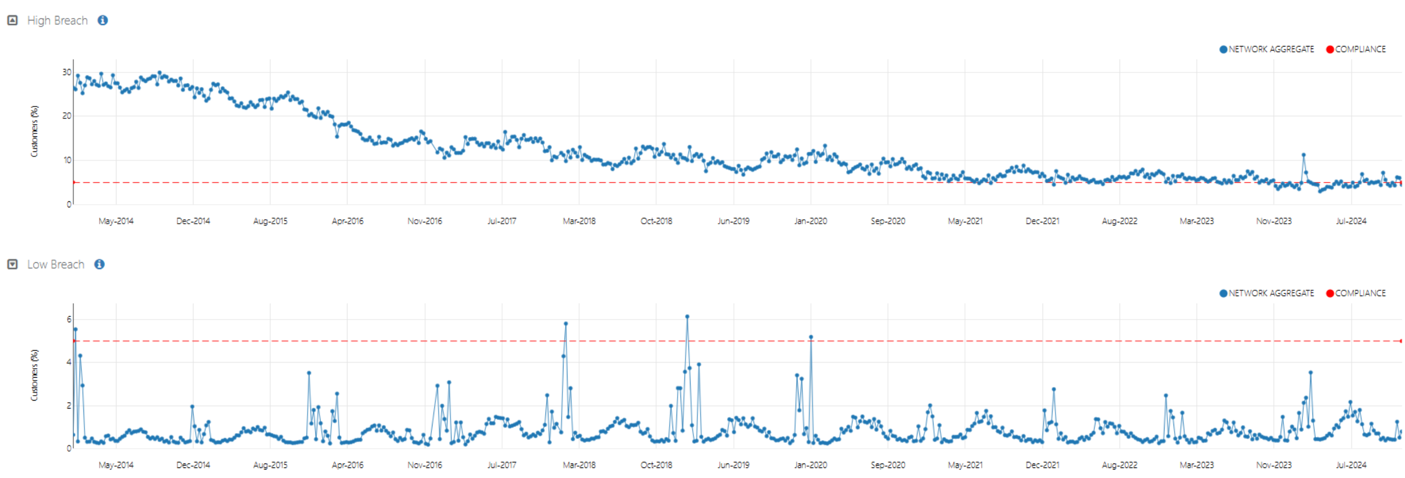

Figure 33: Improvement in voltage compliance

The improvement in voltage compliance seen is primarily due to voltage regulator setting changes that have been actively made to improve voltage levels. Many of the regulators were changed from line-drop compensation to uncompensated settings. These setting changes have been made gradually since 2014 to improve voltage levels and allow better integration of embedded generation such as residential solar PV. Further opportunities for improvements in compliance are being explored, including the trialling of dynamic voltage management system for which site selection and business functional requirements are in progress.

12.6.1.2. Customer supply compliance program

This is a reactive program that addresses quality of supply issues identified by customers within AusNet electricity distribution network. It focuses on taking immediate corrective actions in response to customer complaints.

Where customer issues can be resolved by adjusting transformer tap settings or phase balancing, these are allocated to the appropriate operational cost code and are not included in this program.

- The typical work undertaken under this program includes:
- Upgrading distribution transformers
- Rearranging the network to distribute customers evenly
- Reducing circuit loading by upgrading, or splitting circuits
- Splitting LV networks by installing new distribution substations

12.6.1.3. Steady state voltage compliance program

This a proactive forward-looking investment plan to manage the existing and emerging voltage constraints in AusNet 22 kV and low voltage distribution network.

AusNet has developed an economic approach to valuing the impact of overvoltage on solar generation. This approach uses outputs from AusNet Substation Health tool (part of the Explore tool) and future voltage compliance assessment, which classifies potential solutions to the existing and future voltage non-compliance issues at a distribution substation level.

The approach estimates the cost of solar generation that is constrained due to voltage non-compliance issues and compares this to the cost of augmentation options that will enable that solar generation to be unconstrained or less constrained.

The following is a summary of the approach:

- A solar forecast with a moderate uptake is applied to each non-compliant distribution substation to determine the expected exported energy to the distribution network.
- The expected exported energy is valued using the minimum feed-in tariff (FiT).
- The network topology is extracted from AusNet geospatial system, SDMe, to determine where in the network the constrained substations are positioned and the critical equipment likely to be causing the voltage noncompliance, i.e., zone substation, line voltage regulator, distribution substation etc.
- The expected exported energy is aggregated to the equipment that has been identified as causing the voltage non-compliance issues. This is the value of constrained expected exported energy due to voltage non-compliance and forms the value of unserved generation.
- The constrained expected exported energy per annum is used to calculate the benefits of potential network and non-network solutions.
- A net present value (NPV) assessment is made to determine the highest NPV option. A potential solution is justified when the value of estimated enabled export of previously constrained generation exceeds the cost of the augmentation that allows that generation.
- The justified NPV option with the largest net benefit is then included into our network development plans

The proposed program expenditure is derived from an assessment approach that aims to maximise the net economic benefit to customers by augmenting the network to enable increased export of solar PV generation. The economic assessment observes actual customer voltage performance and values the unserved generation of rooftop-solar due to voltage constraints using the feed-in-tariff (FiT).

In identifying the proposed preferred program to improve steady state voltage compliance, AusNet considered four alternative options:

- Option 1 - Do nothing
- Option 2 - Only address existing voltage issues
- Option 3 - Address both existing and future voltage issues
- Option 4 - Aiming for zero constraints

Options 2 and 3 following the economic approach. Option 4 applies a similar approach to Options 2 and 3, considering multiple solutions to remove constraints in the low voltage and the 22 kV network to allow for zero constraints, however the preferred solution does not necessarily deliver the most positive net benefit to all customers. Instead, it is focussed on delivering the largest generation export possible, regardless of net benefit.

AusNet proposed preferred solution is Option 3, at a cost of $38 million ($2018) over the 2022-26 EDPR period, which represents a prudent and efficient network augmentation investment to address voltage constraints.

Applying a discount rate of 6.44% per annum, this proposed program option has a net economic benefit of $453 million (Real $2018) over the forty-five-year assessment period. It will improve the voltage performance of approximately 228,000 customers and will increase presently constrained generation export by 70% over the 2022-26 period.

12.6.1.4. DER Integration technology program

This program addresses the requirements of the technology platform to enable better visualisation, optimisation and orchestration of DER.

Traditionally the most modelling of the network has occurred at higher voltage levels, with little to no analysis being

done on the LV network. Uptake of DER and bi-directional flows places an emphasis on the LV network to understand its impact on the upstream network as customers produce and consume electricity.

At AusNet, the power-flow models of the network are currently derived from the geo-spatial system, SDMe, and fed into a power-flow engine, namely Siemens PSS Sincal. Only the 22 kV network data is extracted into the Sincal platform with load data approximated by a manual process involving SCADA measurements and AMI data. Work to automate this process and align t o the Common Information Model (CIM) concept is now underway.

The technology program also includes activities on establishment of the foundation required for a future ready forecasting model and a DER Management System as part of the Advanced Distribution Management System (ADMS) upgrade.

The investments proposed in this program of work comprise of the following activities:

- Future Ready Forecasting Model – Enhancement of current Demand Forecasting model, including automation, additional data inputs and inclusion of DER uptake forecast
- HV LV Modelling – Development of the foundation for a HV to LV network load flow model and analytical capability for entire network to enable better planning.
- GIS Network Data Quality Improvements – Work to improve the quality of data in the GIS, to overcome current limitations of SDMe.
- Spatial Application Rationalisation – Work to rationalise existing SAMS and SAMS OPS spatial applications into the SDMe Network Viewer, and repoint downstream interfaces from SAMS and SAMS OPS to SDMe or the Data Lake
- Demand Response Management Enablement – Productionise demand response incentives for residential and DER customers, including payment structures and innovative tariff options.
- Distributed Energy Resource Management System (DERMS) – Work is being undertaken utilising both ARENA funding and network innovation funding to develop DERMS capability that will need to integrate into the ADMS.
- P2P trading – Activities to facilitate AusNet providing meter data to third party trading platforms. This investment includes funding to enable manual data transfer to and from retailers, with data collected and sent via email.

Other power quality related issues are discussed below and how they are maintained within the code limits.

12.6.2. Power Factor

Customer connection agreement stipulates the power factor requirement as per the EDCoP.

12.6.3. Harmonics

Investigations are carried out where harmonics have deviated from the limits and corrective actions will be instigated where necessary. The zone substation power quality meters (PQM) provide voltage harmonics data. This information shows that voltage harmonics are generally within the code limits except at few zone substations. It should be noted here that some PQM have failed to communicate resulting in loss of data. This issue is being investigated and is expected to be resolved during the year.

12.6.3. Inductive interference

By design the generation of radio or TV interference on the network is avoided. This is mainly achieved using type tested equipment and suitably designed components. In addition, routine cyclic inspections and maintenance procedures ensure that the network is maintained in a good condition to ensure RFI & TVI is not generated or limited to levels not affecting the customers.

12.6.4. Negative Sequence Voltage

The South Gippsland network has experienced negative sequence voltage issues for some time (ref. Section 4.5.4). AusNet has attempted to bring this within code by initiating a number of projects. This includes transposing 66 kV sub-transmission lines at strategic locations. However, due to the onerous nature of the EDCoP limits, it is not economical to bring the negative sequence within limits.

12.6.5. Monitoring Quality of Supply

In previous years AusNet fleet of power quality monitors have not been providing sufficient data to meet all of the EDCoP clause 20.4.7 requirements. In 2017 AusNet initiated a project to improve this situation. The scope of the project included upgrading power quality monitoring software, establishing Ethernet/fibre communication to all Zone Substation PQ meters, establishing communication to all Feeder Extremity meters and an automated process for developing Compliance and Business reports.

This project was successfully completed in early 2018. As a result, PQ data is captured from dedicated PQ meters to meet the compliance as per the above clause.

AusNet is continuing trialling a new PQ meter to be used for Feeder Extremities PQ measurements replacing the current EDMI fleet.

Additionally, AusNet is continually developing its AMI meter data analytics to monitor the level of voltage compliance in accordance with AS 61000.3.100.

12.7. Processes to ensure compliance with the measures and standards

AusNet strives to ensure compliance with the measures and standards for reliability and quality of supply. The processes AusNet has in place are described in this section.

12.7.1. Processes for compliance – Reliability

AusNet monitors its network reliability against the targets set by the AER in the EDPR for the current regulatory control period. Distribution network investments are undertaken to improve network reliability in response to the STPIS incentive mechanism. The reliability focus investments include:

- Distribution feeder sectionalising by installing Automatic Circuit Reclosers (ACR) and Automatable Gas Switches (GS).
- Implementing Distribution Feeder Automation (DFA). Now Ausnet is upgrading this scheme to a more advanced version, Fault location, isolation, and service restoration (FLISR) scheme.
- Installing Animal Proofing Insulation, particular on distribution pole substations.
- Following an 'S' Factor centred asset management program
- Installing Fuse-savers to minimise fuse operations due to transient events.
- In AusNet reliability improvements is a continuous process. Apart from the specific programs targeting network locations where investments are needed to improve reliability, the ongoing maintenance, inspections, and replacement of deteriorated assets will also contribute to improving network performance.
- In addition to the above mentioned investments, Ausnet has identified 11 Worst Served Feeders where opportunity lies to improve reliability for vulnerable communities. A proposal to improve reliability in these areas is currently under consideration, with implementation planned to commence from 2026.

Table 44: Feeders proposed for improved reliability

Area	Feeders
Bendoc	BM8B31
Benalla	BN11
Cann River	CNR1, CNR2, CNR3

Kinglake	KLK11
Murrindindi	MDI1
Moe	MOE13
Mansfield	MSD1
Newmerella	NLA31
Woori Yallock	WYK13

12.7.2. Processes for compliance – Quality of Supply

AusNet monitors quality of supply utilising power quality monitors permanently installed at zone substations and feeder extremities as well as AMI data as outlined previously. In addition to these power quality measurements, measurements using portable devices are undertaken to investigate customer complaints on power quality. These unforeseen reactive actions are necessary due to changes in the customer load profile or unexpected localised network loading issues. The actions taken to resolve power quality issues include:

- Distribution feeder upgrades, new feeders, or feeder reconfiguration.
- Distribution substation upgrades or installing new substations.
- Low Voltage network upgrades, reconfiguration, new LV lines or fuse upgrades.
- SWER network augmentations including upgrading or providing new isolating transformers.

12.8. Service Target Performance Incentive Scheme Information from the EDPR

Table 44 and Table 45 outline the information on the Service Target Performance Incentive Scheme (STPIS) contained in AusNet the AER's Final Decision for the 2022-26 Electricity Distribution Price Review (EDPR) period.

12.8.1. AER's Final Decision on STPIS 2022-26 Electricity Distribution Price Review (EDPR)

Table 45: AER's Final Decision 2022-26 EDPR AusNet

AusNet Proposal	AER Final Decision
Cap on revenue at risk of ±4.5%	Cap on revenue at risk of ±4.5%
MED threshold beta of 2.8	MED threshold beta of 2.8
Proposed performance targets based on its five years historical averages.	The AER accepted AusNet proposal, where AusNet performance targets was based on its five years historical averages.

AusNet proposed a new Customer Service Incentive Scheme, which eliminated the need for the telephone parameter in the STPIS.	The AER accepted our new Customer Service Incentive Scheme where the reward and penalty is capped at ±0.5%. As a result, the telephone parameter was removed from the STPIS calculation.

Table 45: Performance targets for SAIDI, SAIFI, and MAIFI: 2022-26

Measure	Feeder Class	2022	2023	2024	2025	2026
Unplanned SAIDI	Urban	87.190	87.190	87.190	87.190	87.190
	Rural Short	195.160	195.160	195.160	195.160	195.160
	Rural Long	293.692	293.692	293.692	293.692	293.692
Unplanned SAIFI	Urban	0.891	0.891	0.891	0.891	0.891
	Rural Short	2.007	2.007	2.007	2.007	2.007
	Rural Long	2.628	2.628	2.628	2.628	2.628
Unplanned MAIFI	Urban	2.817	2.817	2.817	2.817	2.817
	Rural Short	5.657	5.657	5.657	5.657	5.657
	Rural Long	9.920	9.920	9.920	9.920	9.920

13. Asset Management

This section provides information on AusNet asset management approach. This includes a summary of AusNet asset management system and how distribution losses are addressed.

13.1. Asset Management System

Effective and efficient asset management enables an organisation to achieve its objectives. It provides the framework to facilitate the development of strategies and works programs to ensure the objectives are achieved consistently and sustainably over time.

13.2. Scope of the Asset Management System

The scope of the asset management system includes all assets providing network services to customers as identified in the Electricity Distribution Licence issued to AusNet Electricity Services Pty Ltd by the Essential Services Commission.

More specifically this includes:

- Sub-transmission and distribution lines, power cables and associated easements and access tracks.
- Distribution zone substations, switching stations, communication stations and depots including associated electrical plant, buildings, and civil infrastructure.
- Protection, control, metering, and communications equipment.
- Related functions and facilities such as spares, maintenance, and test equipment.
- Asset management processes and systems such as System Control and Data Acquisition (SCADA) and the Enterprise Asset Management system, SAP.

13.3. Asset Management Framework

The asset management framework is informed by a regular assessment of the external business environment and the AusNet's five-year business and financial plans. These plans influence the asset management policy and the development of the 20-year asset management strategies.

The five-year asset management plans are guided by the organisational plans and objectives and the asset management strategies and asset management objectives. These asset management plans identify the management of projects and programs of change and the application of standards to the life cycle of network assets.

The framework is completed with monitoring and evaluation of performance to identify improvement opportunities throughout the entire asset management framework.

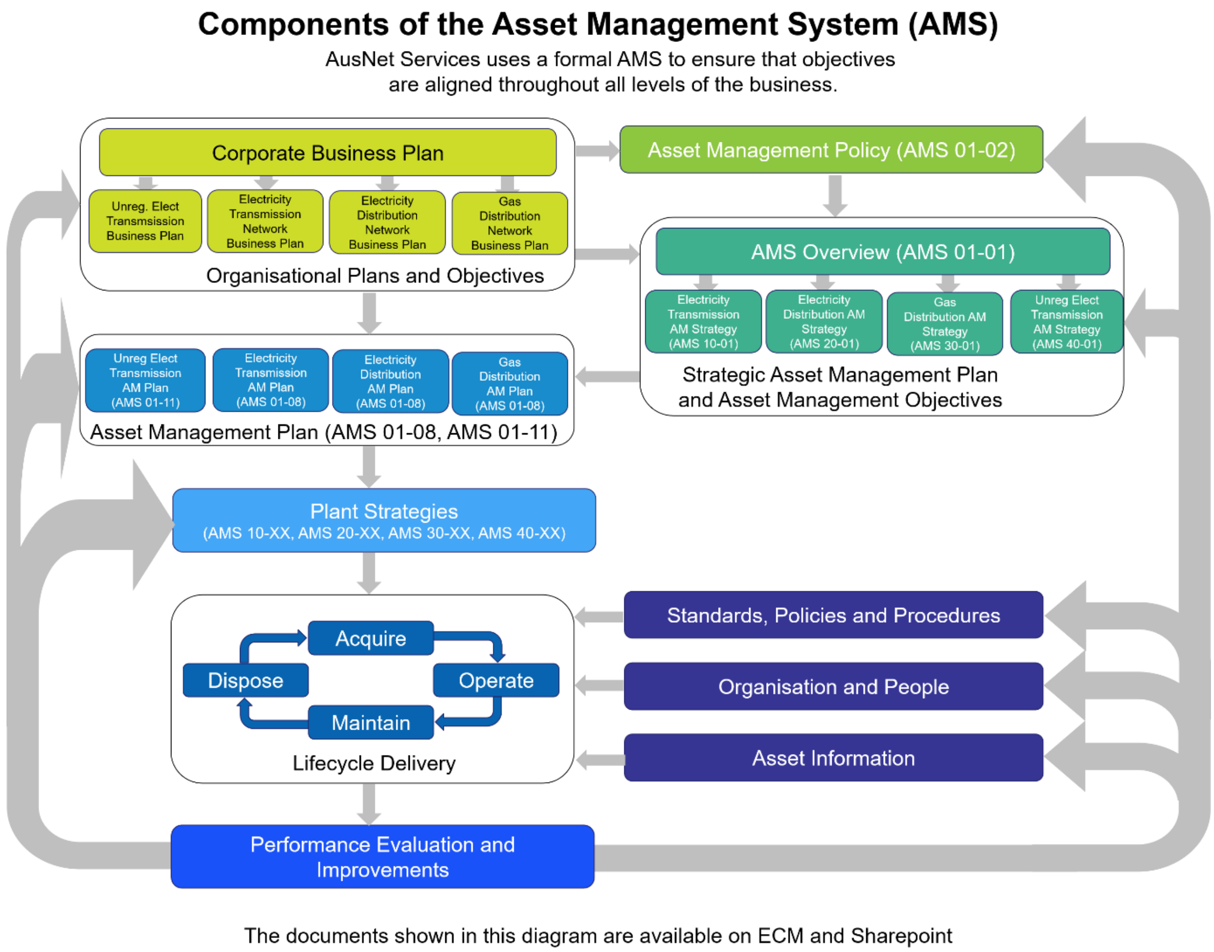

Figure 34: Asset Management Framework

13.4. Asset Management Methodology

AusNet is focused on delivering optimal distribution network performance at efficient costs. Except in the case where outputs are mandated, this requires an explicit cost benefit analysis to be undertaken in order to assess whether the overall economic value of expenditure is positive.

In doing this, AusNet assesses the incremental costs of delivering an incremental change in network performance to customers, relative to the incremental benefits accruing to customers from the delivery of that enhanced network performance.

The asset strategy ensures that all decisions to augment, replace, or maintain network assets are justified on economic grounds. The benefits are a function of the explicit customer value proposition, or proxy via the adoption of minimum performance standards, which are stipulated in legislation or other statutory or regulatory instruments.

The various drivers that are brought to bear when undertaking AusNet Cost Benefit Analysis are summarised in Figure 35.

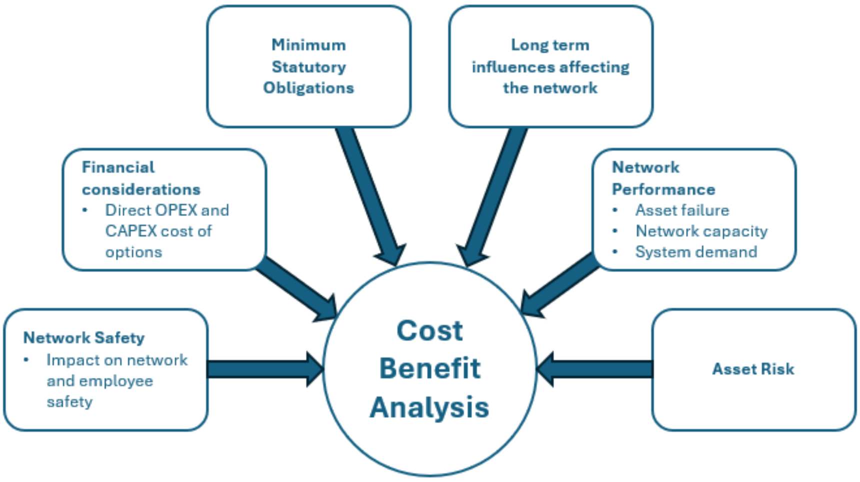

Figure 35: Cost Benefit Analysis Drivers

An annual review of the various drivers and the outcome of cost benefit analysis is developed in the form of an Asset Management Plan. This plan provides a five-year view of the key issues and risks affecting the network and details the expenditure program.

13.5. Key Asset Management Strategies

A list of the current Asset Management strategies for the electricity distribution network is attached in Appendix C:

Asset Management Strategy Reference.

In the current low demand growth environment, the key strategies affecting the forward works program are the Enhanced Network Safety Strategy and the individual plant strategies. Additionally, AusNet is required to maintain the Rapid Earth Fault Current Limiting (REFCL) technology during Total Fire Ban days.

The Enhanced Network Safety Strategy describes opportunities to develop and implement network asset management initiatives and programs that continuously reduce network related health and safety risks 'as far as practicable' (AFAP) for customers, public and personnel, in line with the requirements of the Electricity Safety Act 1998. This incorporates AusNet aspiration to reduce serious incidents through successive regulatory periods.

The individual plant strategies describe how AusNet intends to focus on stabilising failure trends and risk trends. In particular, the emphasis is on stabilising equipment failure trends over time by matching replacement rates to the deterioration rate of those assets nearing the end of their effective service life.

Consistent with amendments to the Electricity Safety (Bushfire Mitigation) Regulations 2023[22], introduced on 1 May 2016, AusNet has implemented REFCL technology in 22 nominated zone substations.

13.5.1. Enhanced Network Safety Strategy

The Enhanced Network Safety Strategy describes the safety related risks apparent on the network and the program of economically justified work that is intended to meet the regulatory obligation to reduce risk AFAP.

The key risks arise through asset failures resulting in the risk of electrical shock and fire ignition. The risk of ground fires

which occur in densely populated, heavily vegetated areas in extreme weather conditions is of particular significance as there are major consequences that can result from these fires.

Modelling of the risks associated with the failure of some classes of assets such as cross-arms, poles and conductor has been completed using a fire loss consequence model. This model assists in identifying the economic volume of asset replacements and the location of the assets which present the greatest risk.

Several programs of work arise from the analysis and modelling.

These programs result in one of the following actions:

[22] Available: https://www.legislation.vic.gov.au/as-made/statutory-rules/electricity-safety-bushfire-mitigation-regulations-2023

- Replacement of deteriorated assets in specific areas (in some cases the consequence of asset failure is so great that the replacement of an asset is 'brought forward' so that the asset does not reach a state of advanced deterioration before it fails); and
- Programs to prevent external factors impacting the network such as fitting animal and bird proofing to complex high voltage overhead structures to reduce the risk of fire ignition due to animal and bird impact.

13.5.2. Plant Strategies

Plant Strategies contain information on how AusNet maintains a risk management system designed in accordance with AS ISO 31000 Risk Management – Guidelines to ensure risks are effectively managed to provide greater certainty for the owners, employees, customers, suppliers, and the communities in which we operate.

The risk of each asset is calculated as the multiplication of probably of failure (PoF) of the asset and the consequence of failure (CoF). The risk is then extrapolated into the future accounting for forecast changes in PoF and CoF.

In the distribution network, AusNet aims to maintain risk. Risk treatments required to achieve this over time include replacement, refurbishment, and maintenance activities, and are developed based on current risk and extrapolated risk. The overall approach to quantified asset risk management is detailed in AMS -01-09. Section 5.1, 5.2 and 5.3 of this document describe the considerations and methodologies to determine PoF, Cof, and risk treatments that are unique to individual asset classes.

Risk treatments are required to maintain risk by targeting reduction of PoF or CoF depending on the nature of the risk. Treatment measures include asset replacement, asset refurbishment, inspections, testing or system redesign, and are achieved through capital projects or operational expenditure. Risk treatment options are described in the section on 'Risk Treatment' in AMS 01-09.

Capital replacement is a major component of asset risk management. The prerequisites for replacing assets:

- replacement of an asset will result in a material risk reduction
- risks can't be feasibly managed through maintenance or refurbishment
- monetised risk exceeds the replacement cost – ie replacement is economic.

13.5.3. Rapid Earth Fault Current Limiter (REFCL) Implementation

A REFCL is electrical protection technology being installed to reduce the risk of fire ignition associated with phase to earth faults on the 22 kV network.

A REFCL operates when a single phase-to-earth fault occurs. Its operation causes the phase voltage of the faulted phase to be reduced to near earth potential (zero volts), thereby working to eliminate the flow of fault current. This compensation also results in phase to ground voltage rise from a nominal 12.7 kV to 22 kV on the un-faulted (healthy) phases, adding more stress to assets on the medium voltage network.

The location and timing for implementation of the REFCL technology is prescribed in Schedule 2 of the Electricity Safety (Bushfire Mitigation) Regulations 2013.

The Bushfire Mitigation Regulations stipulate three Tranches with delivery due by the first of May in the years 2019, 2021 and 2023. All REFCL are now installed as per the Regulations and is illustrated in Figure 36.

Further information may be found on AusNet website[23] and in AusNet Bushfire Mitigation Plan – Electricity Distribution Network[24]

The Victorian government information on REFCL deployment can be found at the Department of Environment, Land, Water, and Planning (DELWP) website[25].

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[23] https://www.ausnetservices.com.au/about/community/powerline-bushfire-safety-program/rapid-earth-fault-current-limiter-program

[24] AusNet, Bushfire Mitigation Plan – Electricity Distribution Network. Available: https://www.ausnetservices.com.au/-/media/project/ausnet/corporate-website/files/about/regulatory-publications/bfm-10-01-admin-update-afdrs-v28-nov-22.pdf

[25] https://www.energy.vic.gov.au/safety/powerline-bushfire-safety-program/safety-devices

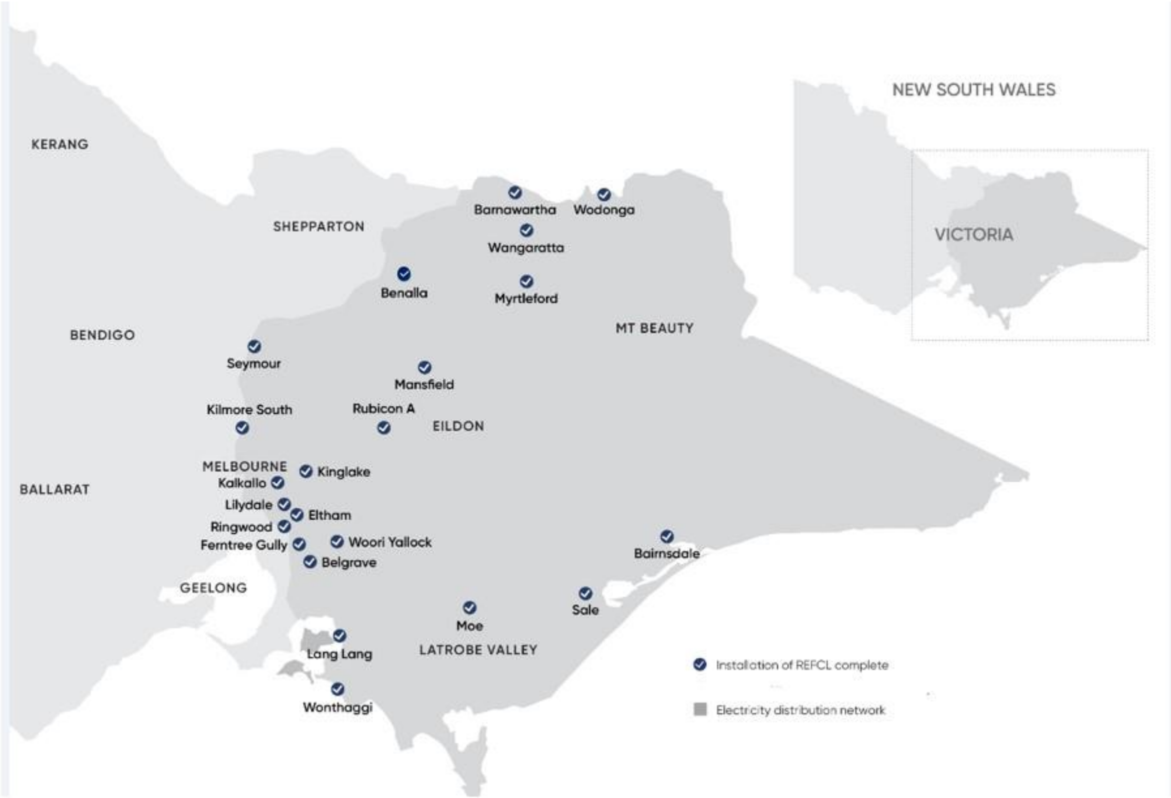

Figure 36: REFCL Location and Delivery Timetable

13.6. Distribution losses

This section provides details required by Schedule 5.8 (k) (1A) of the NER v.200, and explains how AusNet accounts for the cost of distribution losses. Clause 19.2(b) of the EDCoP issued by the ESC states:

> "A distributor must use best endeavours to:
>
> ....
>
> (b) develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution system assets and plans for the establishment and augmentation of transmission connections… to minimise the risks associated with the failure or reduced performance of assets; and in a way which minimises costs to customers taking into account distribution losses."

In the EDCoP, the terms:

'Distribution losses' means electrical energy losses incurred in distributing electricity over a distribution system.

'Distribution system' in relation to a distributor, means a system of electric lines and associated equipment at nominal voltage levels of 66 kV or below.

Further, NER Chapter 5, clause 5.17.1 (c)(4)(vii) requires changes in electrical energy losses to be considered in the RIT-D.

In compliance with these obligations, AusNet considers network losses in planning and development of distribution assets.

AusNet fully accounts for the economic value of reductions in system losses (or increases if this were the case) in the economic assessment of augmentation and asset replacement projects. This is achieved through the following analysis:

- Network power flow studies are used to determine the change in MW system losses both before and after project implementation at maximum demand.
- A load loss factor of 0.4 (ratio of losses at average demand to losses at peak demand) is applied to determine average network losses.
- This is multiplied by 8,760 hours per annum for network projects to determine energy savings per annum from network losses reduction. For network support options such as generation the expected annual hours of operation are used in the calculation.
- This is multiplied by $45 to provide an annual economic benefit for the reduction in system losses associated with project work. A figure of $45 represents typical cost of electricity but is a higher end figure to account for the fact that losses are proportional to the square of the load and are much higher at higher demands. This figure will be escalated by the square of the load growth to reflect the relationship between network losses and load growth.
- This economic benefit is included in Net Present Value analysis to determine projects options that deliver the highest overall economic benefit. Issues that may impact on system limitations identified through asset management.

Issues, including those that impact on system limitations, are identified through the Asset Management System and the planning process mentioned in the previous sections.

13.7. Further information on Asset Management

Further information on the asset management system, asset management strategies, and the methodology adopted by AusNet may be obtained by contacting the listed representative in the Disclaimer at the beginning of this report.

14. Demand Management Activities

Schedule 5.8 (l) of NER addresses demand management activities undertaken on the AusNet network. Since 2012 when AusNet embarked on a strategy to strengthen its Demand Side Participation (DSP) capability, AusNet has undertaken several Embedded Generation and Demand Management (DM) activities.

AusNet Network Innovation team conducts trial projects, analyses options and provide input to network planning processes. The Network Planning and Future Network Program team are responsible for the Demand Management portfolio and consider deployment of embedded generation and non-network solutions as part of the network planning process.

In addition, Under Frequency Load Shed (UFLS) targets by AEMO, to load shed at least 60% of the 'total power system load' (NER clause 4.3.1(k)) in event of significant multiple contingencies is becoming a challenge for distribution networks given the strong uptake of DER. The UFLS is now an area of focus for DNSPs, AEMO and jurisdictional Governments to ensure ongoing power system security. AEMO and DELWP are having regular DNSP engagements for investigation of short, medium and long-term solutions at 66kV and 22kV level to manage UFLS.

The Industry Engagement Strategy aims to facilitate co-operative engagement in network planning between DNSPs and proponents of non-network solutions and is published on AusNet external website[26].

14.1. Non-Network Solutions

The following non-network solutions were deployed by AusNet in the past year:

- Mobile generation: Temporary generation was installed to manage residential summer peak demand in Euroa and Kalkallo. Outside of the summer months, generators were deployed to reduce the impact of planned outages to customers during asset replacement and augmentation works.
- Demand Management (DM): A portfolio of commercial & industrial (C&I) customers has been maintained over the past few years, particularly on feeders with emerging summer peak demand constraints.
- Stand Alone Power Systems – Tranche 1: In 2021, tender submissions were requested for a first tranche of stand-alone power systems (SAPS) to supply fringe-of-grid customers. The target areas were selected based on high ongoing OPEX, avoided replacement CAPEX and to improve reliability of supply to these customers.

  All 17 sites from Tranche 1 were commissioned in early 2023.
- Stand Alone Power Systems – Tranche 2: Expanding on from SAPS Tranche 1, Tranche 2 will involve the delivery of additional SAPS for fringe-of-grid customers. Planning for Tranche 2 has been ongoing with construction expected during CY2025.
- Network Support Agreement (NSA): Three NSAs have been executed for 3rd parties to provide demand support via either embedded generation or battery storage facility. These include 7MVA support for DRN 22kV feeder, 3MVA for WGL 22kV feeder, and 5MVA for PHI 22kV feeder.

Prior to each summer, feeders forecasted to reach thermal overload in all three regions were analysed for C&I DM potential. Areas of network with contingency risk were also analysed. Large C&I customers were contacted to gauge their interest in providing demand management services across the summer period. Presently, the portfolio across the three regions comprises approximately ~4.5 MW of demand reduction capacity. This portfolio capacity has reduced over recent years due to a number large C&I customers opting not to renew expired agreements.

GoodGrid CPD is an ongoing Critical Peak Demand tariff that is a default arrangement for our large commercial and industrial customers. It incentivises them to reduce energy demand on 5 days of high demand per summer.

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[26] A copy of the Demand Side Engagement Strategy can be viewed at AusNet Services' website: http://www.ausnetservices.com.au/About+Us/Regulatory+Publications.html A copy of the Industry Engagement Strategy can be viewed at AusNet website: http://www.ausnetservices.com.au/About+Us/Regulatory+Publications.html

14.2. Key issues arising from applications to connect embedded generation

AusNet received 19 enquiries to connect embedded generators during 2022.

Four existing enquiries reached the 'connection agreement' stage this year, with two becoming committed this year

The key issues identified during the connection enquiry stage were:

- Obligations and liabilities needed to be assessed on a case-by-case basis and negotiated with the proponents. With lack of standard documentation being able to be provided to the customer with ambiguous requirements
- Project coordination challenges were not uncommon, particularly with multiple proposals at the same site, at various stages of the connection application process.
- Time taken for system studies to be completed by the proponent.
- Enquiry stage is an iterative process, with considerable amount of time elapsing before an agreement is reached for connection.

14.3. Actions taken to promote non-network proposals

Since 2021, a range of actions have been undertaken to promote non-network solutions within the AusNet distribution network, including:

14.3.1. Non-Network Opportunities

In early 2021, AusNet evaluated proposals from service providers for a Phillip Island Non-Network Solution. The 5MW/10MWh battery facility was commissioned in 2023 and the Network Support Agreement has been executed. It is expected that the battery will provide support to the network peak demand from 2023/24 summer and remove the need for temporary diesel generators.

The business will continue to promote non-network opportunities on the AusNet website Non-Network Opportunities (ausnetservices.com.au) and direct requests for proposals to providers listed on AusNet Industry Engagement Register.

14.3.2. Grid-Connected Microgrids for Energy Resilience, SAPS and Battery Energy Storage Systems (BESS)

Due to the bushfires in the 2019/2020 summer and the drive to reduce network operational costs, AusNet investigated opportunities for SAPS to improve network resilience. A first tranche of SAPS was commissioned in May 2023 which included 17 SAPS each with one customer connected. This is still the number of regulated SAPS in AusNet's network, i.e. 17 SAPS and total of 17 customers connected to SAPS.[27]

A second tranche of SAPS has been business case approved and is expected to be delivered by CY25.

Grid-connected microgrids are also being assessed for suitability across the network, similar to the MAGS system at Mallacoota. SAPS, BESS and Grid-Connected Microgrids will be a feature of future planning opportunities and assessed based on suitability, safety, reliability, resiliency and economics in-line with any regulatory changes.

[27] The final regulatory framework for SAPS in Victoria was brought in in July 2024. Prior to that, these SAPS were unable to be classified as regulated SAPS. https://www.legislation.vic.gov.au/in-force/statutory-rules/national-electricity-victoria-regulated-stand-alone-power-systems/001

14.3.3. Battery Energy Storage Systems (BESS)

AusNet distribution network is experiencing strong growth in residential solar uptake which resulted in increasing challenges such limited solar hosting capacity and maintaining voltage compliance. In the meantime, maximum demand is expected to continue to grow due to electric vehicle and electrification. The Network is facing the challenge of balancing the grid, when solar energy production is high and demand is low during the day, and then drops off as demand peaks in the evening, i.e., the duck curve

Several Battery Energy Storage Systems (BESS) are being installed and commissioned in 2025 to evaluate their effectiveness in increasing solar hosting capacity, improving supply quality and deferring network augmentation.

Community battery energy storage systems are being deployed as an alternative solution to traditional network augmentation. LV batteries are being installed at high solar penetration areas of the network, with the purpose of managing excess solar export, reducing peak demand and regulating voltage on the LV network. It will also deliver direct benefits to customers, such as removing export limits and enabling more solar connections.

14.3.4. Battery Tariff

The Battery Tariff Trial focuses on developing and implementing new tariff structures to optimize the integration and operation of Community Batteries and Battery Energy Storage Systems. These tariffs include two for Neighbourhood Batteries and two for BESS, designed as two-way time-of-use (ToU) tariffs with specific pricing mechanisms for import/export and demand charges. The tariff enables customers to interact with the market, allowing retailers to request and transition customers onto these tariffs while ensuring accurate data aggregation and billing. The key objective is to gather insights into peak loads and excess solar generation during midday for effective battery charging and discharging, paving the way for new tariff structures. This initiative supports managing future peak demand growth, addressing minimum demand voltage and thermal issues, and minimizing or deferring network augmentation, aligning with AusNet's commitment to innovation and demand management in the EDPR framework.

14.3.5. EV Tariff Trial

The EV Tariff Event Management Trial is designed to explore direct incentives as a mechanism for managing maximum and minimum demand on the network. The trial enables AusNet to call upon EV customers during high-demand days to curtail charging or on low-demand days to increase charging within predefined periods. Participants are rewarded based on their response from their baseline during these events, fostering engagement while helping to manage network load. Insights from the trial will support the development of future tariff structures, helping to manage future demand, minimize network augmentation, reduce costs for customers, and enhance grid reliability, particularly during minimum and maximum system load periods. This initiative aligns with AusNet's broader commitment to innovation in demand management and the energy transition.

14.4. Plans for non-network solutions over the forward planning period

AusNet Service Services will engage with network support providers over the forward planning period in compliance with the RIT–D test for augmentations greater than $6M and at other times as required. AusNet has published on its public website an Industry Engagement Strategy and maintains an Industry Engagement Register.

For traditional network augmentation projects with an estimated capital expenditure less than $6 million, AusNet will continue to evaluate the suitability of non-network alternatives and publish Requests for Proposals to service providers listed on the Industry Engagement Register as requirements are identified.

AusNet Service's Demand Side Engagement Strategy[28] facilitates co-operative engagement in network planning between DNSPs and proponents of non-network solutions. This document describes the processes by which AusNet will identify potential non-network, demand-side participation measures and engage with service providers on a case-by-case basis to consider non-network options in its asset management strategy.

[28] A copy of the Demand Side Engagement Strategy can be viewed at AusNet Services' website: https://www.ausnetservices.com.au/about-us/network-regulation/regulatory-publications

Demand-side or non-network service providers are encouraged to contact AusNet where they believe they can deliver a valuable network support service.

AusNet will continue to:

- Maintain a web page where providers of non-network solutions can view AusNet approach to Industry Participation.
- Encourage Industry service providers to contact AusNet where they believe they can deliver a valuable network support service via a non-network solution. Providers are added to AusNet Industry Engagement Register.
- Maintain the portfolio of commercial and industrial demand management customers for availability during the summer period. The portfolio is reviewed annually in response to changing network conditions and customer demand management performance data. The program will continue to enlist customers that are supplied by constrained feeders with 10% POE or 50% POE risk in the short (1-3 years) or supplied from zone substations that are forecast to carry energy at risk under an N-1 contingency.
- Engage commercial and industrial customers on demand-based tariffs, e.g., customers with an annual consumption greater than 160 MWh that are on tariffs with a critical peak demand (CPD) component. This CPD charge provides a significant pricing signal to customers to reduce the demand over five nominated critical peak demand days during the summer period (1 December to 31 March). The response to this incentive has improved and this is expected to continue.
- Utilise future Demand Management Innovation Allowance funding to build additional demand management capability, tools and techniques, focussing on residential customer demand management that may be deployed in urban growth corridors and remote communities.

14.5. Embedded generation enquiries and applications

AusNet supports customers wishing to connect embedded generators to our electricity distribution network. The information Table 46 covers the connection of embedded generators that are required to or intend to register with AEMO. These embedded generators typically have a capacity greater than AEMO's standing exemption from registration, which is currently 5 MW.

Table 46: Information on establishing or modifying connection for embedded generation

2024* Embedded Generation - 66 kV	**North**	**East**	**Central**	**Total**
(i) *Connection* enquiries received under clause 5.3A.5		6		**6**
(ii) *Applications to connect* received under clause 5.3A.9	2	2	0	**4**
(iii) The average time taken to complete *applications to connect* (months)	N/A*	N/A	N/A	**18**
2023 Embedded Generation - 22 kV	**North**	**East**	**Central**	**Total**
(i) Connection enquiries received under clause 5.3A.5	3	3	0	**6**
(ii) Applications to connect received under clause 5.3A.9	0	0	0	**0**
(iii) The average time taken to complete applications to connect (months)	N/A	N/A	N/A	**9**

**Applications are still active and therefore the time to complete is not currently available*

** Data is collected from 24/10/2023 to 20/11/2024*

15. Information Technology and Communication Systems

This section presents an overview of AusNet investments in information technology and communication systems, as required under schedule 5.8 (m) of the NER.

15.1. Expenditure in the previous, current and future regulatory periods

Our plans for the FY2026-31 regulatory period build on the strategic direction and momentum from the previous regulatory period, in which AusNet had focused on cautiously modernising our business capabilities in an uncertain and complex environment.

Our investments for this period are also aimed at readying AusNet to evolve in response to the expected business environment post covid period; that is, a more uncertain and complex electricity environment with consumers' investment in technologies such as local solar PV generation and battery storage significantly impacting the management of network assets and resources

AusNet key outcomes of this current period are to:

- Improve relationships with and outcomes for customers
- Leverage and extend investments, working with partners to continue reducing costs
- Increase digitisation and automation, leveraging digital technologies such as cloud, automation and artificial intelligence to improve customer outcomes and increase efficiency
- Be future ready for increasing impact of Distributed Energy Resources (DER)
- Cyber security uplift, protecting our customers' and business information, and mitigate risks to system reliability stemming from a cyber-attack.

Sound information technology is critical to supporting AusNet increasing role in balancing residential generation and supply of electricity with residential demand, the investments already made provided the basis to enable the business to deal with the uncertain future.

The following details some of the proposed programmes currently being implemented:

- Enhanced customer interactions and experiences through easy to access and value-added information and services, including enhancement of customer communications and notifications, including enhanced capabilities to accurately identify location of faults that could cause safety issues
- Comply with metering regulatory requirements,
- Develop low voltage network management capability to cater for increased Distributed Energy Resources (DER), including impact analysis modelling and the development of tactical tools to monitor and manage two-way energy flows across the distribution network to optimise network safety, resilience and reliability and ultimately enhance customer service delivery.
- Develop enhanced energy demand forecasting to understand and better manage the changes in energy demand due to Distributed Energy Resources, to increase network reliability in peak times, through the development of tactical models of DER take up and hosting capacity.
- Drawing on meter data to enhance capabilities and enable us to accurate identify the location of various types of faults that could cause safety issues to the public, damage to either AusNet or customer's assets or parts of the network.
- Enhance communications capabilities and field mobility to leverage network and asset management investments, improve service performance and reliability, and improve safety providing operational

functions to the field. This includes expanding mobility tools to our field force to support a broader range of field tasks and activities, upgrading mobile devices and providing access to a broader range of applications and information.

- Develop data and analytics capabilities through information management to better manage risk and provide the information required for business decision making, including an enterprise management platform, automated asset risk modelling reporting, and advanced analytics.
- Continued investment in information security to ensure the safety of customer information and protect the electricity networks and business systems from cyber-attack.
- Enhanced employee capabilities making it easier to respond to customer queries through work collaboration and communication tools; and
- Lifecycle management of systems and platforms including rationalisation and consolidation to maintain the overall integrity and stability of the network, optimise investment, manage risk, and efficiently maintain services to our customers.

Continued uplifting cyber security capabilities including:

- Initial implementation of Privileged Access Management for IT assets
- Default multi-factor authentication enabled for all users Refresh of storage, server and data centre, which

  has included:
- Delivery of several end-of-life technology and capacity uplift refresh initiatives in the storage, server and data centre domains.
- Maintenance of the currency of database platforms supporting several critical business systems.

Delivered improvements leading to technology and capacity uplift and efficient information management, such as:

- Enhanced security functionality.
- Improvements to the employee experience.
- Improved spatial capability.
- Reduction of the risk of business disruption and outages due to obsolete (end of life / out of support) infrastructure and/or constrained capacity thereby enabling AusNet to continue to meet its service and regulatory obligations; and
- Implemented initial phase of an Asset Risk Management program, including 7 asset risk classes, embedding data models for lines and stations.

Secured cloud infrastructure, and have begun process to migrate a select group of applications to the cloud.

Continuous improvements to Enterprise Asset Management (EAM) and Enterprise Resource Planning (ERP) which has delivered several business-initiated enhancements to improve the effectiveness of the EAM/ERP solution, including business systems and interfaces associated with network management.

15.2. Priorities and expenditure in the current regulatory period

In the current regulatory period (2022-2026), AusNet seek to deliver on key strategic enablers with evolving customer expectations at the centre of these developments. Driving better outcomes for customers that are aligned to their expectations is the central focus of technology investments, which is balanced with value delivery through lower costs and effectively managed risk.

For the current regulatory period, AusNet proposed investments in technology are divided into thirteen programs of work, with each program grouped into one of the following work stream themes:

- Distributed Energy Resources (DER)
- Intelligent Operations

- Cyber Security
- Lifecycle
- Metering

The five work stream themes, and thirteen programs of work are summarised in the following sections.

15.2.1. Distributed Energy Resources (DER)

DER uptake is increasing on AusNet's distribution network, digital enabling technologies is required alongside traditional network augmentation to integrate DER efficiently and support increased customer choices.

15.2.1.1. Integration of DER

In accordance with a new licence condition to deliver the Victorian Emergency Backstop Mechanism, in 2024 AusNet implemented the capabilities required to meet compliance with the licence condition, providing a mechanism to remotely curtail or interrupt customer solar, where required, to maintain system security. Below is a summary of the activities under the new Emergency Backstop Mechanism:

- No interruption or curtailment of electricity generation was carried out in 2024. Ausnet have not commenced testing of devices (after initial commissioning). During initial commissioning, Ausnet run tests to verify that the device is capable of responding correctly to controls.
- As of 20 December 2024, 996 solar customers were connected as emergency backstop enabled during 2024. This reflects approximately 5 MW of connected solar capacity that was connected in 2024 as backstop enabled.

When referring to backstop enabled systems, we are referring to systems that were connected with that capability approved. However, at times, systems will lose connectivity with AusNet's network and utility server, in which case that are unable to be curtailed.

AusNet will seek to roll out further enhancements of this functionality in line as a foundational platform for further DER enablement and Distribution System Operation (DSO) capabilities. AusNet will also continue to seek improvements in network monitoring, forecasting and modelling capability especially on the low voltage distribution network to better understand the network behaviour in a high DER distribution network. This is expected to underpin more accurate understanding of constraints and hosting capacity. Ultimately supporting more efficient network investment decisions and increased network utilisation through dynamic operating envelopes and demand flexibility.

15.2.1.2. Future Distribution Network Management

As the network continues to evolve, core technology platforms must support, orchestrate, and manage the growth in DER. There is also rising customer expectations for improved network performance, service delivery, reduced outages, quicker supply restoration, and smart control/integration and information systems, as well as the ability to proactively manage customer demand.

This programme of work will ensure AusNet has the network management capabilities required to be able to meet expected demands and customer expectations. AusNet is achieving this through the inflight, multi-phase, Advanced Distribution Management System (ADMS) program to implementing the required technology platform and capabilities. The execution of Phase 2 of this program continued in 2024, with final Fault Location, Isolation, and Service Restoration (FLISR) capabilities to be implemented in 2025. The ADMS Phase 3 program entered design phase, targeting delivery of system performance, forecasting, optimisation, fault management, Embedded generation integration, DER integration and mobile integration capabilities from 2025/26 onwards.

15.2.1.3. Customer Information Services

This programme will enable AusNet to better track and understand evolving interactions with our customers as the network is increasingly used for two-way energy flow. Implementing an effective Customer Information Management solution will enable AusNet to provide appropriate advice and manage the range of customers and interactions required. This will also ensure the business is well placed to meet regulatory rule changes, which increasingly require sophisticated data management capabilities.

Building on the Customer Self-Serve and Digital Customer Experience projects completed to date, in 2024 AusNet commenced work on consolidating and simplifying customer connection portals, and improve end-to-end process flow and user experience. Initial capabilities went live with the Solar Emergency Backstop program, with the bulk of improvements scheduled for 2025 implementation.

In response to the February 2024 storms, and consistent with Victorian Essential Services Commission Enforceable Undertaking, investment has also been made to improve the performance and reliability of AusNet's Outage Tracker communications platform. External review recommendations have been addressed in 2H2024, and further performance enhancements will be delivered in 2025.

15.2.2. Intelligent Operations

Many advanced sensors and smart meters create valuable sources of data that can be leveraged by the business to improve network reliability and efficiency while reducing customer bills. There is a need to continue enhancing the use of data to improve grid availability, security, and DER integration. This work stream aims to balance the risks to asset and network reliability with the cost of managing those risks through improved data and analytics, automation, visualisation, modelling, and risk management.

15.2.2.1. Information Management

AusNet will continue to extend the Information Management platform to develop the capability to analyse network performance, supported by advanced automation on near real time data. This will support better decision making, more efficient operations and network reliability..

In 2024, work continued on Digital Simplification, a program of 10 initiatives to streamline, consolidate and improve the efficiency of AusNet's information system landscape. Commenced in 2023, the remaining scope items of cloud migration of network strategy and planning databases and standardisation of robotic process automation are scheduled to be completed in early 2025.

15.2.2.2. Outage Management

The business will integrate the various sources of asset, maintenance and interconnectivity data required to plan outages and augment the network. This programme will simplify outage management, providing field crews with automated reports and live data dashboards, while supporting network controllers with advanced automation and analytics.

The ADMS Phase 3 programme, which entered design phase in 2024, and field mobility capability improvements (detailed under Workforce Collaboration), will contribute to the target outcomes of the this programme of work.

15.2.2.3. Workforce Collaboration

As employees progress within the organisation they acquire knowledge, which is specialised to the company's operations, structure, and culture. This programme will make these unique insights more readily accessible regardless of workforce location or business area, creating productivity gains.

To support transition of the Distribution field works delivery partner, in 2024 ICT work commenced on implementing enhanced field mobility capabilities, to improve visibility and management of critical fault works, and systems integrations to enable effective data flows. This program will be completed in 2025, with further capability build and broader systems integration planned to follow.

15.2.2.4. Corporate Enablement

AusNet runs multiple enterprise applications to support day-to-day operations. The enterprise application landscape and related integrations underpin the continuity of all operational processes. As such, AusNet must ensure these core functionalities are adaptable in an increasingly changing environment, while also being robust and reliable solutions for all employees

To maintain system currency and security, and provide an enabler for improved business processes, AusNet in 2024 commenced Enterprise Resource Planning (ERP) suite migration onto the next-generation system. This project will be completed in 2025.

15.2.3. Cyber Security

This work stream aims to balance risks and costs of protecting the distribution network, and customer and business information and assets through improvements in cyber security capabilities.

15.2.3.1. Cyber Security

Investment in cyber security in the forecast period will ensure compliance to current and emerging regulations, including sufficient investment to comply with the regulatory obligations under AEMO's Australian Energy Sector Cyber Security Framework (AESCSF). This will provide better protection of critical assets required to supply energy to customers, better protect critical customer and operations data, and support ongoing development and measurement of cyber security capabilities within the organisation.

In 2024 AusNet achieved AESCSF Security Profile 2 (SP-2) compliance. This was achieved following key cyber security upgrades including uplift of identity governance for critical applications, refreshing end-of-life firewalls, migration of web security controls, and uplifting digital asset management of critical applications and dependencies.

The cyber security program will continue to progress towards AusNet achieving target SP-3 compliance (AESCSF's highest rating) and reduce our key risks. Key initiatives planned include Operational Technology threat & vulnerability management, enhancements to security operations centre technology and practices, uplift in cloud security technology and practices, uplift our data protection technology and practices, rollout of engineering standard operating environment workstation, and further uplift in cyber security policies and procedures.

15.2.4. Lifecycle

This work stream aims to efficiently manage the risks and costs of maintaining core systems resiliency by undertaking prudent lifecycle refreshes.

15.2.4.1. Technology Asset Management (TAM) - Applications

AusNet has approximately 200 systems that require periodic patching and enhancements, as aligned to the standard technology lifecycle. This ensures ongoing vendor support, application of performance and security patches and bug fixes, limits downtime and ultimately underpins reliability of critical operations across the business.

Technology Asset Management Applications upgrades are prioritised and implemented annually, based on risk criticality. Key upgrades completed in 2024 include currency upgrade of AusNet's core middleware integration platform, replacement of end-of-life control room call record platform, and modernisation of control room interfaces. The risk prioritised program will continue in 2025.

15.2.4.2. Technology Asset Management (TAM) - Infrastructure

Technology infrastructure comprises the hardware, software, network resources and services required to deliver information and technology to the business. This programme of work ensures the business has sufficient capacity, performance, and service levels to maintain the operation of technology systems whilst optimising data centre infrastructure to operate with more efficiency and resilience.

Consistent with Applications discussed above, Technology Asset Management Infrastructure upgrades are progressed based on risk criticality. Key upgrades completed in 2024 include replacements of end-of-life SCADA firewalls and workstations, distribution site network routers, and test beds used for new connections. The risk prioritised program will continue in 2025.

15.2.4.3. Corporate Communications

Corporate communications at AusNet comprise technology networking devices (i.e., Wi-Fi, routers), internet services provision and gateways, as well as data centre interconnectivity, covering both systems and assets.

As is conducted for critical systems above, this programme expenditure on capacity management and like-for-like lifecycle refreshes ensures the network performance requirements are met for both existing and future business growth.Key activities in 2024 include the redesign of SCADA network switches for resiliency and high availability, and continuation of the multi-year network modernisation program of data centre networking and fit-out upgrades.

15.2.5. Metering

This work stream aims to balance the risks and costs of maintaining AusNet metering systems, while meeting new regulatory compliance requirements.

15.2.5.1. Metering Lifecycle

AusNet has technology systems that operate and coordinate metering functions with the rest of the distribution business.

In the current regulatory period, these systems will require periodic refreshes and patching to ensure they remain supported and well maintained. Maintaining ongoing vendor support and patch and bug fixes will limit downtime, which underpins the reliability of critical operations across the business.

Additionally, there is new market compliance rules that will require capability extensions of systems to ensure compliance. These refreshes will achieve both the compliance and lifecycle activities to achieve lowest possible costs. Compliant metering solutions underpin AusNet smart network capabilities, providing timely delivery of the necessary consumption, supply quality and exceedance data, which enables key functions in the monitoring of the electricity distribution network.

In addition, a large population of AusNets AMI meter fleet age profile will exceed the forecast 15 year operational life advised by the meter manufacturer. Ongoing review of operational and lifecycle management and strategies to mitigate against larger scale meter population failure are proposed to be implemented during this forecast period.

16. Regional Development Plan

A regional development plan consisting of maps of AusNet network is provided on our corporate website, in accordance with the requirements of schedule 5.8 (n) of NER: https://dapr.ausnetservices.com.au/

These maps are updated annually and/or following major project completions to provide the latest available information on current and emerging feeder, zone substation and sub-transmission network limitations.

Any information provided using the system limitation template must be read in conjunction with the reporting DNSP's DAPR.

17. Advanced Metering Infrastructure Benefits

This section aims to highlight benefits of utilising advanced metering infrastructure (AMI) technology to support life support customers, guide network planning and industry response initiatives, and support network reliability initiatives.

17.1. Utilisation of AMI data for life support customers

In accordance with the requirements of clause 19.4.6(a) of the EDCoP, AusNet keeps vulnerable customers safe by utilising AMI technology installed across power network based on following:

Our last gasp system integrated within AMI analysis tool known as explore generate alerts to inform us when a Life Support Customer (LSC) becomes de-energised. When these alerts occur, a notification is delivered to the Customer Service Centre which triggers a process for a contact to be made with the person that resides at the NMI location.

Life support customers within and adjacent to upcoming planned outage areas have their recorded AMI voltage data reviewed, to ensure that those customers have been correctly referenced to the correct supply substation and have received the correct notification.

As a continuous improvement we have identified potential opportunity to make process more efficient.

17.2. Network planning and demand side response

In accordance with the requirements of clause 19.4.6(b) of the EDCoP AusNet utilises AMI data as explained below:

(a) To determine historical and ten-year forward looking demand forecasts for our network which enables us to prepare for both maximum and minimum demands;

(b) The AMI data information forms basis of driving optimum solution for network augmentation and replacement projects with an estimated delivery expenditure;

(c) In accordance with the schedule2 of the EDCoP, AusNet publishes voltage performance reporting;

(d) The AMI Data is assessed to mitigate power quality issues raised by customers; and

(e) Network planning assessment for evaluating load transfer capability at sub-transmission lines, zone substations and HV feeders.

17.3. Network Reliability Initiatives

In accordance with the requirements of clause 19.4.6(c) of the EDCoP, AusNet Services has:

(f) developed the Explore tool, that provides alerts when voltage profiles are abnormal, which are reviewed daily, resulting in regular dispatch of fault response crews to site, often before partial faults escalate to become larger events or issues.

(g) an Advanced Distribution Management System (ADMS) is under development which will ensure that near real time outage information, as provided by AMI, will be delivered to the Control Room, to ensure fault crews are dispatched at the earliest possible time.

17.4. Quality of Supply

Refer Section 12 and website (https://dapr.ausnetservices.com.au/)

A. Glossary

Abbrev.	Name	Abbrev.	Name
AFI	Australian Forest Industries	**MDI**	Murrindindi Zone Substation
APM	Australian Paper Maryvale	**MFA**	Maffra Zone Substation
BDL	Bairnsdale Zone Substation	**MJG**	Merrijig Zone Substation
BDSS	Bairnsdale Switching Station	**MOE**	Moe Zone Substation
BGE	Belgrave Zone Substation	**MPS**	Morwell Power Station
BHWF	Bald Hills Wind Farm	**MSD**	Mansfield Zone Substation
BM8	Bombala feeders from NSW (BOM)	**MWE**	Morwell East Zone Substation
BN	Benalla Zone Substation	**MWN**	Morwell North Zone Substation
BRA	Boronia Zone Substation	**MWL**	Morwell Zone Substation
BOM	Bombala Zone Substation (Essential Energy)	**MWTS**	Morwell Terminal Station
BRT	Bright Zone Substation	**MWW**	Morwell West Substation
BWA	Barnawartha Zone Substation	**MYT**	Myrtleford Zone Substation
BWN	Berwick North Zone Substation	**NH**	North Heidelberg (Jemena)
BWR	Bayswater Zone Substation	**NLA**	Newmerella Zone Substation
CBTS	Cranbourne Terminal Station	**NRN**	Narre Warren Zone Substation
CF	Clover Flat Zone Substation	**OFR**	Officer Zone Substation
CLN	Clyde North Zone Substation	**PHI**	Phillip Island Zone Substation
CLPS	Clover Power Station	**PHM**	Pakenham Zone Substation
CNR	Cann River Zone Substation	**RUBA**	Rubicon 'A' Zone Substation
CPK	Chirnside Park Zone Substation	**RVE**	Rowville Zone Substation
CRE	Cranbourne Zone Substation	**RWN**	Ringwood North Zone Substation
CYN	Croydon Zone Substation	**RWT**	Ringwood Terminal Station 22 kV Yard
DN	Dandenong Zone Substation (UE)	**RWTS**	Ringwood Terminal Station
DRN	Doreen Zone Substation	**SFS**	Sassafras Zone Substation
DSH	Dandenong South Zone Substation	**SLE**	Sale Zone Substation
DVY	Dandenong Valley Zone Substation (UE)	**SLF**	Sugarloaf Reservoir Melbourne Water Substation
ELM	Eltham Zone Substation	**SMG**	South Morang Zone Substation
EPG	Epping Zone Substation	**SMR**	Seymour Zone Substation
ERTS	East Rowville Terminal Station	**SMTS**	South Morang Terminal Station

FGY	Ferntree Gully Zone Substation	**ST**	Somerton Zone Substation (Jemena)
FTR	Foster Zone Substation	**TGN**	Traralgon Zone Substation
GNTS	Glenrowan Terminal Station	**TRC**	Tumut River Council - NSW (Essential Energy)
HPK	Hampton Park Zone Substation	**TSTS**	Templestowe Terminal Station
HPS	Hume Power Station	**TT**	Thomastown Zone Substation
KLK	Kinglake Zone Substation	**TTS**	Thomastown Terminal Station
KLO	Kalkallo Zone Substation	**TWF**	Toora Wind Farm
KMS	Kilmore South Zone Substation	**UWY**	Upwey Zone Substation
LDL	Lilydale Zone Substation	**WGI**	Wonthaggi Zone Substation
LFD	ESSO Longford	**WGL**	Warragul Zone Substation
LGA	Leongatha Zone Substation	**WN**	Wangaratta Zone Substation
LLG	Lang Lang Zone Substation	**WO**	Wodonga Zone Substation
LSSS	Leongatha South Switching Station	**WOTS**	Wodonga Terminal Station
LYD	Lysterfield Zone Substation	**WT**	Watsonia Zone Substation
LYS	Loy Yang South Zone Substation	**WYK**	Woori Yallock Zone Substation
MBTS	Mt Beauty Terminal Station	**YEA**	Yea Substation
MBY	Mt Beauty Zone Substation	**YN**	Yallourn North Open Cut Zone Substation
MDG	Mt Dandenong Zone Substation	**YPS**	Yallourn Power Station

B. Asset Management Strategy Reference

Document Scope	AMS Number	Description
High Level Summary	AMS 20-01	Electricity Distribution Network
High Level Summary	AMS 20-03	Network Contingency Plan
Process and System	AMS 20-12	Augmentation
Process and System	AMS 20-13	Enhanced Network Safety Strategy
Process and System	AMS 20-14	Infrastructure Security
Process and System	AMS 20-15	Quality of Supply
Process and System	AMS 20-16	Distribution Network Planning Standards and Guidelines
Process and System	AMS 20-23	Vegetation Management
Process and System	AMS 20-24	Sub-transmission line and Station Data for Planning Purposes
Process and System	AMS 20-30	Demand Forecasting Procedure
Process and System	AMS 20-35	Network Support Services
Process and System	AMS 20-50	Steady State Voltage Compliance
Plant Strategy	AMS 20-52	Conductor
Plant Strategy	AMS 20-53	Zone Substation Capacitor Banks
Plant Strategy	AMS 20-54	Circuit Breakers
Plant Strategy	AMS 20-55	Civil Infrastructure
Plant Strategy	AMS 20-56	Indoor Switchboards
Plant Strategy	AMS 20-57	Crossarms
Plant Strategy	AMS 20-58	Distribution Transformers
Plant Strategy	AMS 20-59	Electrical Earths
Plant Strategy	AMS 20-60	MV Switches and ACRs
Plant Strategy	AMS 20-61	MV Fuse Switch Disconnectors
Plant Strategy	AMS 20-62	HV Switches, Disconnectors and Earth Switches
Plant Strategy	AMS 20-63	Instrument Transformers
Plant Strategy	AMS 20-64	Sub Transmission Towers, Insulators and Ground Wires
Plant Strategy	AMS 20-65	Insulated Cable Systems
Plant Strategy	AMS 20-66	Insulators – High and Medium Voltage
Plant Strategy	AMS 20-67	Line Surge Arresters
Plant Strategy	AMS 20-68	Line Voltage Regulators
Plant Strategy	AMS 20-69	Pole-Top Capacitors
Plant Strategy	AMS 20-70	Poles
Plant Strategy	AMS 20-71	Power Transformers and Station Voltage Regulators
Plant Strategy	AMS 20-72	Protection and Control Systems
Plant Strategy	AMS 20-73	Public Lighting
Plant Strategy	AMS 20-76	Service Cables
Plant Strategy	AMS 20-77	Surge Arresters in Zone Substations
Plant Strategy	AMS 20-79	Neutral Earthing Devices
Plant Strategy	AMS 20-80	Auxiliary Power Supplies
Plant Strategy	AMS 20-81	Communication Systems
Plant Strategy	AMS 20-90	Zone Substation Transformer Contingency Plan

C. Asset retirement and de rating asset groupings

Assets have been categorised to align with the NER. Schedule 5.8 Clause (5) (b1) refers to individual asset reporting and Clause (5) (b2) refers to assets that can be reported together, referred to as Group Reporting in this Appendix.

Table 47: AusNet proposed Asset Grouping

Individual reporting	Group reporting
Appendix A Zone substation transformers **Appendix B Circuit breakers 66kV** **Appendix C Switchboards** **Appendix D Capacitor banks** **Appendix E Circuit breakers 22kV in zone substation**	**Appendix F Poles** **Appendix G Pole top structures** G.1 Cross-arms G.2 Insulators G.3 Surge arrestors G.4 Pole top capacitors G.5 Other (dampers, armour rods, spreaders, brackets etc.) **Appendix H Switchgear** H.1 Automatic Circuit Reclosers H.2 Gas switches H.3 Isolators H.4 Other **Appendix I Overhead conductor LV, HV and ST** **Appendix J Underground cables** **Appendix K Other underground assets** K.1 Cable head terminations K.2 Pits K.3 LV Pillars **Appendix L Distribution plant** L.1 Circuit breakers – other L.2 Substation kiosk L.3 Distribution transformers L.4 Isolators L.5 Services L.6 Ring Main Unit L.7 Earthing cables L.8 Regulators L.9 Combo switches **Appendix M Protection and control room equipment and instrumentation**

	M.1 Protection relay M.2 Voltage Regulator Relay M.3 VAR (Capacitor Bank) controllers M.4 Batteries M.5 AC and DC distribution equipment M.6 Voltage/Current transformers **Appendix N Communications and SCADA** N.1 Remote telemetry unit **Appendix O Zone substation switchyard equipment** O.1 Surge arrestors O.2 Busses O.3 Terminations O.4 Steel structures

D. Retired or de-rated grouped assets

Appendix B outlines the methodologies and assumptions used for grouped assets listed in Appendix D of this report and should be read in conjunction with Section 5, Network Asset Retirement and De-ratings.

The complete asset management strategies are available upon request to the contacts outlined in the Disclaimer at beginning of this report.

D.1. Poles

The methodologies and assumptions for all sub-transmission and distribution pole replacements are described in Asset Management Strategy AMS 20-70.

This document outlines the methodologies that are combined to develop AusNet pole replacement strategy. Applying a condition-based replacement forecast over the next five years requires replacement or reinforcement of all very poor condition poles.

D.2. Cross-arms

The methodologies and assumptions for all sub-transmission and distribution pole top cross-arm replacements are described in Asset Management Strategy AMS 20-57. This document outlines methodologies that are combined to develop AusNet cross arm replacement strategy.

The cross-arm replacement volumes are forecast to decline from observed historical volumes to a sustainable replacement level, due to completion of the aerial inspection program.

D.3. Insulators

The methodologies and assumptions for all HV and MV insulators are described in Asset Management Strategy AMS 20-66. This document outlines methodologies and strategies such as new assets, inspection, maintenance and replacement that are combined to develop AusNet insulator replacement strategy. Insulators are also replaced when a pole or cross-arm is replaced.

D.4. Surge Arrestors

The methodologies and assumptions for all line surge arrestor replacement are described in Asset Management Strategy AMS 20-67. This document outlines methodologies such as failure mode effect criticality analysis and risk assessment strategies that are combined to develop AusNet surge arrestor replacement strategy.

Some installed surge arresters are not capable of operating with REFCLs. These surge arresters will be replaced as part of the REFCL implementation line hardening works. Surge arrester replacements are targeted in the highest bushfire risk areas as the REFCLs are being installed these areas.

D.5. Pole Top Capacitors

The methodologies and assumptions for all pole top capacitor replacement are described in Asset Management

Strategy AMS 20-69. This document outlines methodologies such as Inspection, Failure Mode, probability of failure assessments, consequence and risk treatment strategies that are combined to develop AusNet pole top capacitor replacement strategy.

D.6. Conductors and associated Hardware

The methodologies and assumptions for all conductor and conductor hardware replacement are described in Asset

Management Strategy AMS 20-52. This document outlines methodologies such as Failure Modes Effects Criticality Analysis and risk analysis strategies that are combined to develop AusNet conductor and conductor hardware replacement strategy.

It also identifies the number of assets that need to be replaced to manage bushfire ignition risk, conditional asset failures and mitigate reliability impacts.

Deteriorated steel conductor ties and fiberglass conductor spacers are replaced in conjunction with maintenance activities.

In addition to risk-based conductor replacement, 100km of SWER conductor will also be pro-actively replaced in Codified Areas between 2021 and 2026.

D.7. Gas Switches and Automatic Circuit Reclosers

The methodologies and assumptions for all Medium Voltage Switches and Automatic Circuit Reclosers (ACR) are described in Asset Management Strategy AMS 20-60. This document outlines methodologies such as Inspection, Failure Mode, probability of failure assessments, consequence and risk treatment strategies that are combined to develop AusNet pole top capacitor replacement strategy.

D.8. Isolators

The methodologies and assumptions for all Isolator replacements are described in Asset Management Strategy AMS 20-62. This document outlines methodologies such as Inspection, Failure Mode, probability of failure assessments, consequence and risk treatment strategies that are combined to develop AusNet Isolator replacement strategy.

Most replacements will occur in conjunction with station rebuilds or circuit breaker, instrument transformer, power transformer replacements.

D.9. Underground Cables

The methodologies and assumptions for all Cable replacements are described in Asset Management Strategy AMS 20-65. This document lists the risk mitigation activities required to achieve this over time include replacement, refurbishment and maintenance activities which are developed based on current risk and extrapolated risk. The commission test program is now well established for all new cable circuits, excluding those in URD purely based on the volume of work presented in those estates. The commission test program provides, an opportunity to ensure that substandard circuits are not accepted and placed into service as well as providing a fingerprint of the circuit characteristics that can be used as a guide in determining circuit degradation during the service life of the cable circuit.

D.10. Distribution Transformers

The methodologies and assumptions for all Distribution Transformer replacements are described in Asset

Management Strategy AMS 20-58. This document outlines methodologies such as Inspection, Failure Mode, probability of failure assessments, consequence and risk treatment strategies that are combined to develop AusNet distribution transformer replacement strategy. These methodologies and approaches utilise a combination of age-based replacement and condition-based replacement methods.

D.11. Service Cables

The methodologies and assumptions for all service cable replacement are described in Asset Management Strategy AMS 20-76.

D.12. Protection and Control Room Equipment and Instrumentation

The methodologies and assumptions for all protection and control room equipment and instrumentation replacement are detailed in Asset Management Strategy AMS 20-72, AMS 20-80 and AMS 20-63. These documents outline methodologies such as Inspection, Failure Mode, probability of failure assessment, consequence and risk treatment strategies that are combined to develop AusNet protection and control room equipment and instrumentation replacement strategy.

Protection and control room equipment and instrumentation includes protection relays, voltage regulator relays, VAR (capacitor bank) controllers, batteries, AC and DC distribution equipment and voltage/current transformers.

D.13. Communications and SCADA Remote Telemetry Units

The methodologies and assumptions for all remote telemetry unit (RTU) replacement are described in Asset Management Strategy AMS 20-72. This document outlines methodologies such as Service Age and Functionality Assessment strategies that are combined to develop AusNet RTU replacement strategy.

D.14. Surge Arresters in Zone Substations

The methodologies and assumptions for all Surge Arresters in Zone Substations replacement are described in Asset

Management Strategy AMS 20-77. This document outlines methodologies such as Inspection, Failure Mode, probability of failure assessments, consequence and risk treatment strategies that are combined to develop AusNet Surge Arresters in Zone Substations replacement strategy.

These methodologies and approaches have identified surge arresters that need to be replaced in conjunction with Zone Substation rebuild projects and those as standalone replacements.

E. Demand forecasts

E.1. Maximum demand forecasts for sub-transmission lines -Summer and Winter

Table 48 - Maximum Demand Forecast for sub-transmission - Winter and Summer

Sub-T Loop	Sub-T Loop Name	Firm Capacity Winter (MVA)	23/24 PF - Winter	23/24 Max Winter Demand (MVA)	24/25	25/26	26/27	27/28	28/29	Firm Capacity Summer (MVA)	23/24 PF - Summer	23/24 Max Summer Demand (MVA)	24/25	25/26	26/27	27/28	28/29
CBTS-LYD-NRN-PHM-OFR-BWN-LLG-CLNCBTS	Cranbourne Terminal Station - Lysterfield - Narre Warren - Berwick North - Pakenham - Officer - Lang Lang - Clyde North	283	1.00	236.2	273.2	286.6	303.1	320.6	337.4	243	1.00	284.6	329.8	342.6	357.8	373.8	389.9
RWTS-LDL-WYK-CPK-RWN	Ringwood Terminal Station - Ringwood North - Chirnside Park - Lilydale - Woori Yallock	190	1.00	142.4	152.5	157.3	162.9	169.0	173.0	177	0.99	171.2	197.7	201.3	205.2	209.6	212.5

Sub-T Loop	Sub-T Loop Name	Firm Capacity Winter (MVA)	23/24 PF - Winter	23/24 Max Winter Demand (MVA)	24/25	25/26	26/27	27/28	28/29	Firm Capacity Summer (MVA)	23/24 PF - Summer	23/24 Max Summer Demand (MVA)	24/25	25/26	26/27	27/28	28/29
ERTS-BGE-FGY-ERTS	East Rowville Terminal Station - Ferntree Gully - Belgrave	109	1.00	68.1	79.9	81.4	83.0	84.9	86.6	102	0.98	67.2	80.1	80.9	81.7	82.8	83.9
ERTS-DN-HPK-DSH-DVY-ERTS	East Rowville Terminal Station - Hampton Park - Dandenong - Dandenong Valley - Dandenong South	379	0.99	243.9	289.2	300.7	309.4	316.1	324.1	352	0.98	277.5	310.2	318.4	322.0	325.9	328.9
RWTS-BRA-BWR-CYN-RWTS	Ringwood Terminal Station - Croydon - Bayswater - Boronia	291	1.00	164.5	176.0	180.1	185.4	191.4	197.2	260	0.99	179.5	213.7	216.4	219.5	223.3	227.1
TSTS-SLF	Templestowe Terminal Station - Sugarloaf	0	1.00	20.0	20.6	20.6	20.6	20.6	20.6	0	1.00	20.0	20.6	20.6	20.6	20.6	20.6

Sub-T Loop	Sub-T Loop Name	Firm Capacity Winter (MVA)	23/24 PF - Winter	23/24 Max Winter Demand (MVA)	24/25	25/26	26/27	27/28	28/29	Firm Capacity Summer (MVA)	23/24 PF - Summer	23/24 Max Summer Demand (MVA)	24/25	25/26	26/27	27/28	28/29
TSTS-ELM	Templestowe Terminal Station - Eltham	77	1.00	60.2	63.8	65.0	66.4	68.0	69.5	77	1.00	70.5	81.2	82.2	83.3	84.4	85.6
SMTS-DRN-KLK-MDI-RUBA-YEA-SMR-KMS-KLO-SMTS	South Morang Terminal Station - Doreen - Kinglake - Murrindindi - Rubicon - Yea - Seymour - Kilmore South - Kalkallo	300	0.99	168.8	196.8	209.3	225.5	245.5	264.4	268	0.95	177.7	219.4	230.1	243.6	260.0	276.8
DRN-KLK-MDI-RUBA-YEA-SMR-KMS	Doreen - Kinglake - Murrindindi - Rubicon - Yea - Seymour - Kilmore South	35	0.99	48.6	58.1	59.2	60.5	61.9	63.4	35	0.92	48.1	60.0	60.7	61.7	62.7	63.9

Sub-T Loop	Sub-T Loop Name	Firm Capacity Winter (MVA)	23/24 PF - Winter	23/24 Max Winter Demand (MVA)	24/25	25/26	26/27	27/28	28/29	Firm Capacity Summer (MVA)	23/24 PF - Summer	23/24 Max Summer Demand (MVA)	24/25	25/26	26/27	27/28	28/29
SMTS-EPG	South Morang Terminal Station - Epping	126	1.00	67.2	76.4	81.4	86.7	92.9	98.3	117	1.00	86.0	98.9	103.7	108.8	114.0	119.2
TTS-NEI-NH-WT-TTS	Thomastown Terminal Station - Watsonia - North Heidelberg - Nilsen Electrical Industries	126	1.00	96.7	108.0	112.3	115.9	119.0	121.5	117	1.00	118.3	129.4	131.1	132.6	134.0	136.2
TTS-TT	Thomastown Terminal Station - Thomastown	91	1.00	70.5	75.6	77.7	79.8	82.2	84.4	88	1.00	76.1	83.9	85.1	86.3	87.5	88.6
GNTS-BN	Glenrowan Terminal Station - Benalla	112	0.99	61.0	71.8	73.5	75.4	77.3	79.5	105	0.97	48.3	59.7	60.4	61.2	62.0	62.9
BN-MSD	Benalla - Mansfield	0	0.98	29.6	33.9	34.4	35.0	35.5	36.2	0	0.96	17.1	20.6	20.8	21.2	21.5	21.9

Sub-T Loop	Sub-T Loop Name	Firm Capacity Winter (MVA)	23/24 PF - Winter	23/24 Max Winter Demand (MVA)	24/25	25/26	26/27	27/28	28/29	Firm Capacity Summer (MVA)	23/24 PF - Summer	23/24 Max Summer Demand (MVA)	24/25	25/26	26/27	27/28	28/29
MSD-MJG	Mansfield - Merrijig	0	0.97	13.8	15.4	15.8	16.1	16.4	16.8	0	0.91	2.0	3.0	3.1	3.2	3.2	3.3
GNTS-WN	Glenrowan Terminal Station - Wangaratta	83	1.00	69.4	80.9	82.1	83.4	84.9	86.2	83	0.99	65.6	78.8	79.6	80.4	81.3	82.2
WN-MYT-BRT-MBTS	Mount Beauty Terminal Station - Bright - Myrtleford - Wangaratta	49	1.00	29.4	34.8	35.1	35.5	35.8	36.2	33	0.99	21.0	25.4	25.6	25.9	26.2	26.4
MBTS-MBY	Mount Beauty Terminal Station - Mount Beauty	0	0.96	9.0	9.6	9.6	9.7	9.8	9.9	0	0.75	3.9	3.5	3.5	3.6	3.6	3.7
WOTS-HPS	Wodonga Terminal Station - Hume Power Station	0	1.00	50.0	51.5	51.5	51.5	51.5	51.5	0	1.00	50.0	51.5	51.5	51.5	51.5	51.5

Sub-T Loop	Sub-T Loop Name	Firm Capacity Winter (MVA)	23/24 PF - Winter	23/24 Max Winter Demand (MVA)	24/25	25/26	26/27	27/28	28/29	Firm Capacity Summer (MVA)	23/24 PF - Summer	23/24 Max Summer Demand (MVA)	24/25	25/26	26/27	27/28	28/29
WOTS-WO	Wodonga Terminal Station - Wodonga	87	1.00	50.6	53.7	54.8	56.0	57.4	58.6	65	0.98	54.3	62.5	62.9	63.6	64.3	65.1
WO-BWA	Wodonga - Barnawartha	0	1.00	11.0	11.3	11.5	11.8	12.0	12.3	0	0.97	11.3	12.3	12.4	12.6	12.8	13.0
MBTS-CLPS-CF	Mount Beauty Terminal Station - Clover Flat - Clover Power Station	0	1.00	29.0	29.9	29.9	29.9	29.9	29.9	0	1.00	29.0	29.9	29.9	29.9	29.9	29.9
MWTS-YPS-MOE-WGL-MWTS	Morwell Terminal Station - Yallourn - Moe - Warragul	130	0.99	88.8	100.0	102.9	106.5	111.0	114.8	114	0.99	99.3	115.3	117.4	120.6	124.2	127.9

Sub-T Loop	Sub-T Loop Name	Firm Capacity Winter (MVA)	23/24 PF - Winter	23/24 Max Winter Demand (MVA)	24/25	25/26	26/27	27/28	28/29	Firm Capacity Summer (MVA)	23/24 PF - Summer	23/24 Max Summer Demand (MVA)	24/25	25/26	26/27	27/28	28/29
MWTS-TGN-SLE-MFA-BDSS-BDL	Morwell Terminal Station Traralgon - Sale - Maffra - Bairnsdale - Bairnsdale Switching Station	120	1.00	148.6	177.5	182.0	186.8	192.0	196.3	120	1.00	169.3	196.8	199.9	203.3	207.1	210.5
BDL-NLA	Bairnsdale - Newmerella	0	0.99	9.7	11.5	11.6	11.7	11.8	11.9	0	1.00	9.8	10.9	11.0	11.1	11.2	11.3
NLA-CNR	Newmerella - Cann River	0	0.99	2.0	2.4	2.5	2.5	2.5	2.5	0	1.00	2.2	2.5	2.6	2.6	2.6	2.6
MWTS-LGA-FTR-MWTS	Morwell Terminal Station - Leongatha - Foster	131	1.00	104.6	128.6	130.9	133.2	135.7	138.2	92	0.99	114.1	136.5	138.1	139.9	142.0	144.1
LGA-WGI	Leongatha - Wonthaggi	43	1.00	56.8	68.8	70.3	72.0	73.7	75.4	32	0.99	66.3	76.7	77.7	78.9	80.3	81.7
WGI-PHI	Wonthaggi - Phillip Island	0	0.99	20.7	22.1	22.5	22.9	23.4	23.8	0	0.99	22.8	25.3	25.5	25.7	26.0	26.5

E.2. Minimum demand forecasts for sub-transmission lines

Table 49: Minimum demand forecasts for sub-transmission lines

Sub-T Loop	'N' Export Rating (MW)	'N-1' Export Rating (MW)	Minimum Demand (MW)							
			Actual		10%POE					
			23/24 PF	23/24	24/25	25/26	26/27	27/28	28/29	95% Hours
CBTS-CRE	-7.3	-2.4	-0.98	-10.5	-18.5	-22.6	-26.1	-28.7	-30.7	4.5
CBTS-LYD-NRN-PHM-OFR-BWN-LLG-CLN-CBTS	-13.1	-1.2	-0.44	-67.4	-115.9	-137.8	-156.0	-171.1	-182.4	56.5
ERTS-BGE-FGY-ERTS	0.0	0.0	-0.86	-8.8	-16.6	-19.0	-20.8	-21.9	-22.6	105.25
ERTS-RVE	0.0	0.0	-0.93	-4.6	-7.2	-8.2	-9.0	-9.7	-10.1	12.25
ERTS-DN-HPK-DSH-DVY-ERTS	-5.6	-0.8	0.36	4.6	-19.8	-26.5	-30.8	-34.9	-40.2	10.3
GNTS-BN-MSD-MJG	0.0	0.0	-1.00	-8.3	-13.5	-15.8	-17.9	-19.5	-20.6	26.0
GNTS-WN	0.0	0.0	-0.99	-8.9	-14.3	-16.7	-18.6	-20.2	-21.4	14.5

Sub-T Loop	'N' Export Rating (MW)	'N-1' Export Rating (MW)	Minimum Demand (MW)							
			Actual		10%POE					
			23/24 PF	23/24	24/25	25/26	26/27	27/28	28/29	95% Hours
MWTS-LGA-FTR-MWTS	0.0	0.0	-0.93	-2.3	-8.6	-10.6	-12.2	-13.6	-14.4	1.75
MWTS-TGN-SLE-MFA-BDSS-BDL	0.0	0.0	-0.89	-20.1	-38.0	-45.2	-51.1	-55.6	-58.9	4.3
MWTS-MWL	0.0	0.0	0.36	0.4	-2.5	-3.8	-4.8	-5.5	-6.0	33.8
MWTS-YPS-MOE-WGL-MWTS	0.0	0.0	-0.76	-10.5	-22.2	-26.8	-30.4	-33.2	-35.1	24.3
RWTS-LDLWYK-CPK-RWN-RWTS	-7.8	-5.2	-0.45	-11.5	-25.8	-32.3	-37.3	-41.2	-43.8	48.8
RWTS-BRA-BWR-CYN-RWTS	-1.8	0.0	0.34	-4.5	-18.5	-24.1	-28.2	-31.1	-33.0	18.5
SMTS-EPG-SMTS	0.0	0.0	0.00	0.0	-26.5	-31.9	-36.3	-39.8	-42.4	16.0

Sub-T Loop	'N' Export Rating (MW)	'N-1' Export Rating (MW)	Minimum Demand (MW)							
			Actual		10%POE					
			23/24 PF	23/24	24/25	25/26	26/27	27/28	28/29	95% Hours
SMTS-DRN-KLK-MDI-RUBA-YEA-SMR-KMS-KLO-SMTS	0.0	0.0	-0.84	-57.3	-87.9	-101.9	-114.2	-125.0	-134.1	13.5
SMTS-SMG-SMTS	0.0	0.0	0.35	1.1	-2.5	-3.6	-4.5	-5.2	-5.6	62.5
TSTS-ELM-TSTS	-12.4	-2.6	-0.73	-5.1	-11.5	-14.4	-16.7	-18.4	-19.6	35.3
WOTS-WO-BWA	-0.3	-0.1	-0.50	-1.0	-6.4	-8.3	-9.8	-11.0	-11.8	10.5
MBTS-MBY	0.0	0.0	-0.38	-1.0	-1.8	-2.0	-2.2	-2.3	-2.5	185.8
MBTS-BRT-MYT	0.0	0.0	-0.74	-3.5	-6.6	-7.8	-8.8	-9.7	-10.2	29.3
MBTS-CLPS-CF	0.0	0.0	0.69	0.3	0.0	0.0	0.0	0.0	0.0	112.5
TTS-TT-TTS	0.0	0.0	0.70	2.7	0.0	-0.8	-1.4	-1.8	-2.0	17.5
TTS-NEI-NH-WT-YYS	0.0	0.0	0.00	16.1	12.2	9.4	6.8	3.8	0.9	0.5

E.3. Capacity of sub-transmission network

Table 50 - Available capacity of sub-transmission network

				Winter				Summer			
Sub-T Loop	Sub-T Loop Name	Terminal Station	Installed capacity (MVA)	Firm Capacity Winter (MVA)	Load Transfer Capacity (MVA)	Embedded Generation Capacity (MVA)	Estimated Hours at 95% of Peak Load	Firm Capacity Summer (MVA)	Load Transfer Capacity (MVA)	Embedded Generation Capacity (MVA)	Estimated Hours at 95% of Peak Load
CBTS-LYD-NRN-PHM-OFR-BWN-LLG-CLNCBTS	Cranbourne Terminal Station - Lysterfield - Narre Warren - Berwick North - Pakenham - Officer - Lang Lang - Clyde North	CBTS	406	283	45.5	0.2	7.2	243	45.5	0.2	11.38
RWTS-LDL-WYK-CPK-RWN	Ringwood Terminal Station - Ringwood North - Chirnside Park - Lilydale - Woori Yallock	RWTS	438	190	30.2	4.5	1.9	177	30.2	4.5	16.15
ERTS-BGE-FGY-ERTS	East Rowville Terminal Station - Ferntree Gully - Belgrave	ERTS	203	109	7.8	3.8	1.4	102	7.8	3.8	4.35
ERTS-DN-HPK-DSHDVY-ERTS	East Rowville Terminal Station - Hampton Park - Dandenong - Dandenong Valley - Dandenong South	ERTS	469	379	12.4	8.8	3.6	352	12.4	8.8	5.88

Sub-T Loop	Sub-T Loop Name	Terminal Station	Installed capacity (MVA)	Winter				Summer			
				Firm Capacity Winter (MVA)	Load Transfer Capacity (MVA)	Embedded Generation Capacity (MVA)	Estimated Hours at 95% of Peak Load	Firm Capacity Summer (MVA)	Load Transfer Capacity (MVA)	Embedded Generation Capacity (MVA)	Estimated Hours at 95% of Peak Load
RWTS-BRA-BWR-CYNRWTS	Ringwood Terminal Station - Croydon - Bayswater - Boronia	RWTS	453	291	40.7	2	0.9	260	40.7	2	7.70
TSTS-SLF	Templestowe Terminal Station - Sugarloaf	TSTS	54	0	0	4	0.0	0	0	4	0.00
TSTS-ELM	Templestowe Terminal Station - Eltham	TSTS	154	77	20.9	0	4.4	77	20.9	0	4.97
SMTS-DRN-KLK-MDI-RUBA-YEA-SMR-KMSKLO-SMTS	South Morang Terminal Station - Doreen - Kinglake - Murrindindi - Rubicon - Yea - Seymour - Killmore South - Kalkallo	SMTS	385	300	25.7	83.7	1.2	268	25.7	83.7	3.23
DRN-KLK-MDI-RUBAYEA-SMR-KMS	Doreen - Kinglake - Murrindindi - Rubicon - Yea - Seymour - Killmore South	SMTS	93	35	1.4	8.8	1.2	35	1.4	8.8	3.98
SMTS-EPG	South Morang Terminal Station - Epping	SMTS	234	126	12.2	2	1.2	117	12.2	2	18.14

				Winter				Summer			
Sub-T Loop	**Sub-T Loop Name**	**Terminal Station**	**Installed capacity (MVA)**	**Firm Capacity Winter (MVA)**	**Load Transfer Capacity (MVA)**	**Embedded Generation Capacity (MVA)**	**Estimated Hours at 95% of Peak Load**	**Firm Capacity Summer (MVA)**	**Load Transfer Capacity (MVA)**	**Embedded Generation Capacity (MVA)**	**Estimated Hours at 95% of Peak Load**
TTS-NEI-NH-WT-TTS	Thomastown Terminal Station - Watsonia - North Heidelberg - Nilsen Electrical Industries	TTS	234	126	16.5	0	0.6	117	16.5	0	2.24
TTS-TT	Thomastown Terminal Station - Thomastown	TTS	176	91	11.2	0	1.2	88	11.2	0	5.96
GNTS-BN	Glenrowan Terminal Station - Benalla	GNTS	209	112	0	0.2	3.3	105	0	0.2	3.67
BN-MSD	Benalla - Mansfield	GNTS	65	0	0.5	0	3.7	0	0.5	0	4.22
MSD-MJG	Mansfield - Merrijig	GNTS	64	0	0.5	0	0.9	0	0.5	0	0.50
GNTS-WN	Glenrowan Terminal Station - Wangaratta	GNTS	205	83	4.3	2.3	2.5	83	4.3	2.3	1.24
WN-MYT-BRT-MBTS	Mount Beauty Terminal Station - Bright - Myrtleford - Wangaratta	MBTS	73	49	1.6	0	0.7	33	1.6	0	5.88
MBTS-MBY	Mount Beauty Terminal Station - Mount Beauty	MBTS	41	0	0	0	3.1	0	0	0	1.24

Sub-T Loop	Sub-T Loop Name	Terminal Station	Installed capacity (MVA)	Winter				Summer			
				Firm Capacity Winter (MVA)	Load Transfer Capacity (MVA)	Embedded Generation Capacity (MVA)	Estimated Hours at 95% of Peak Load	Firm Capacity Summer (MVA)	Load Transfer Capacity (MVA)	Embedded Generation Capacity (MVA)	Estimated Hours at 95% of Peak Load
WOTS-HPS	Wodonga Terminal Station - Hume Power Station	WOTS	65	0	0	50	0.6	0	0	50	0.00
WOTS-WO	Wodonga Terminal Station - Wodonga	WOTS	139	87	0	2	1.9	65	0	2	2.48
WO-BWA	Wodonga - Barnawartha	WOTS	64	0	5.4	5	0.0	0	5.4	5	2.24
MBTS-CLPS-CF	Mount Beauty Terminal Station - Clover Flat - Clover Power Station	MBTS	20	0	0	29	1.6	0	0	29	0.00
MWTS-YPS-MOEWGL-MWTS	Morwell Terminal Station - Yallourn - Moe - Warragul	MWTS	214	130	4.3	15.7	2.9	114	4.3	15.7	5.96
MWTS-TGN-SLE-MFABDSS-BDL	Morwell Terminal Station - Traralgon - Sale - Maffra - Bairnsdale - Bairnsdale Switching Station	MWTS	295	120	8.6	109.3	2.8	120	8.6	109.3	7.71
BDL-NLA	Bairnsdale - Newmerella	MWTS	19	0	2.0	0	0.0	0	2.0	0	7.95

Sub-T Loop	Sub-T Loop Name	Terminal Station	Installed capacity (MVA)	Winter				Summer			
				Firm Capacity Winter (MVA)	Load Transfer Capacity (MVA)	Embedded Generation Capacity (MVA)	Estimated Hours at 95% of Peak Load	Firm Capacity Summer (MVA)	Load Transfer Capacity (MVA)	Embedded Generation Capacity (MVA)	Estimated Hours at 95% of Peak Load
NLA-CNR	Newmerella - Cann River	MWTS	48	0	3.0	2	2.5	0	3.0	2	5.96
MWTS-LGA-FTR-MWTS	Morwell Terminal Station - Leongatha - Foster	MWTS	245	131	3.0	21	1.6	92	3.0	21	4.72
LGA-WGI	Leongatha - Wonthaggi	MWTS	82	43	3.0	118.6	1.6	32	3.0	118.6	1.74
WGI-PHI	Wonthaggi - Phillip Island	MWTS	41	0	6.8	5	0.6	0	6.8	5	1.49

E.4. Maximum demand forecasts for zone substations

Table 51 - Maximum demand forecasts for zone substations – Winter and Summer

			Winter								Summer							
				Historical		Forecast 10%POE (MVA)						Historical		Forecast 10%POE (MVA)				
ZSS	Name	Name Plate Rating (MVA)	Firm Capacity Winter (MVA)	2024 PF	2024 Load (MVA)	2025	2026	2027	2028	2029	Firm Capacity Summer (MVA)	23/24 PF	23/24 Load (MVA)	24/25	25/26	26/27	27/28	28/29
BDL	Bairnsdale	81	95.2	0.99	50.6	55.8	57.1	58.5	60.0	61.6	88	1.00	56.1	59.5	60.3	61.3	62.2	63.3

BGE	Belgrave	66	47.3	1.00	30.4	30.9	31.4	31.9	32.5	33.1	40.4	0.97	26.5	30.2	30.3	30.4	30.8	31.1
BN	Benalla	40.5	36.8	1.00	31.3	33.1	34.1	35.2	36.4	37.9	30.7	1.00	31.1	34.7	35.1	35.5	35.8	36.3
BRA	Boronia	99	86.1	1.00	54.3	53.7	55.0	56.4	58.1	59.7	77.8	1.00	68.7	76.7	77.7	78.6	79.7	80.9
BRT	Bright	40	30	1.00	14.7	15.8	16.0	16.2	16.3	16.5	27.9	0.99	8.2	10.3	10.3	10.4	10.6	10.7
BWA	Barnawartha	33	0	1.00	11.0	10.8	11.0	11.2	11.5	11.7	0	0.97	11.3	11.7	11.8	12.0	12.2	12.3
BWN	Berwick North	33	48.1	1.00	29.4	30.7	31.2	31.8	32.4	32.9	38.9	1.00	32.7	35.6	36.0	36.4	36.8	37.2
BWR	Bayswater	81	78.6	1.00	51.1	52.2	53.4	55.0	56.9	58.6	66.2	0.97	48.7	54.5	55.1	55.9	57.0	57.9
CF	Clover Flat	10	7.3	1.00	7.9	7.7	7.7	7.7	7.6	7.6	6.7	1.00	1.4	1.9	1.9	1.9	1.9	1.9
CLN	Clyde North	66	47.8	0.99	66.5	75.5	81.2	87.6	94.4	100.9	43.5	1.00	84.4	92.1	98.0	103.9	110.4	116.9
CNR	Cann River	10	0	0.99	2.0	2.3	2.3	2.4	2.4	2.4	0	1.00	2.2	2.4	2.5	2.5	2.5	2.5
CPK	Chirnside Park	66	48.6	1.00	32.9	34.9	35.7	36.5	37.5	38.5	48.8	0.99	45.0	49.1	49.5	50.0	50.7	51.5
CRE	Cranbourne	66	46.3	1.00	48.3	54.2	56.4	58.5	61.0	63.4	41.1	1.00	62.3	69.9	72.0	73.7	75.3	77.3
CYN	Croydon	99	94	0.99	59.2	60.1	61.6	63.5	65.6	67.7	83	1.00	62.0	70.4	71.4	72.6	74.0	75.4
DRN	Doreen	66	49.1	0.99	52.0	53.7	55.0	56.5	58.1	59.7	45.9	1.00	60.9	68.5	69.4	70.4	71.5	72.6
ELM	Eltham	99	89.1	1.00	60.2	60.2	61.3	62.6	64.1	65.6	80.7	1.00	70.5	76.6	77.5	78.6	79.6	80.8
EPG	Epping	99	92.4	1.00	67.2	72.1	76.8	81.8	87.6	92.8	82	1.00	86.0	93.3	97.9	102.7	107.5	112.5
FGY	Ferntree Gully	93	67.4	1.00	37.8	44.5	45.4	46.4	47.6	48.7	61.8	0.99	40.7	45.4	46.1	46.7	47.3	48.0
FTR	Foster	66	49	0.99	15.9	18.2	18.4	18.6	18.9	19.1	49.1	0.99	18.5	19.3	19.5	19.7	19.9	20.2
HPK	Hampton Park	99	90.7	1.00	45.2	48.6	49.7	50.8	52.3	54.6	81.6	1.00	55.0	63.6	64.4	65.1	66.7	68.8
KLK	Kinglake	10	7.4	0.97	6.8	6.7	6.9	7.1	7.3	7.6	7.4	0.80	6.1	6.0	6.1	6.2	6.3	6.4

KLO	Kalkallo	66	49.1	1.00	53.6	64.1	73.0	85.0	100.2	114.4	49.1	1.00	53.8	68.2	76.3	86.8	99.7	112.7
KMS	Kilmore South	30	14.5	1.00	14.6	15.1	15.6	16.3	17.0	17.7	16.6	1.00	14.9	15.7	16.0	16.5	17.1	17.7
LDL	Lilydale	99	96.9	1.00	48.1	49.6	50.7	52.2	54.0	55.7	90.1	1.00	59.4	63.8	64.5	65.4	66.5	67.7
LGA	Leongatha	73	41.6	1.00	32.0	36.2	36.6	37.1	37.5	38.0	41.5	0.99	29.3	35.1	35.4	35.8	36.2	36.6
LLG	Lang Lang	33	0	1.00	19.9	23.5	24.3	25.4	26.5	27.5	0	1.00	21.3	22.7	23.4	24.4	25.3	26.3
LYD	Lysterfield	33	0	1.00	14.2	15.3	15.6	15.9	16.3	16.7	0	1.00	18.7	20.9	21.2	21.5	21.8	22.2
MBY	Mt Beauty	30	21.4	0.96	9.0	9.5	9.5	9.6	9.7	9.8	19.9	0.75	3.9	3.5	3.5	3.6	3.6	3.6
MDI	Murrindindi	0.5	0	0.98	0.3	0.1	0.2	0.2	0.2	0.2	0	0.89	0.2	0.2	0.2	0.2	0.2	0.2
MFA	Maffra	40	37.8	0.99	26.3	28.1	28.7	29.4	30.2	30.9	31.1	0.98	30.6	31.4	31.7	32.1	32.6	33.1
MJG	Merrijig	20	0	0.97	13.8	14.7	15.0	15.3	15.6	16.0	0	0.91	2.0	2.9	2.9	3.0	3.1	3.2
MOE	Moe	40.5	36.3	0.99	28.5	30.8	31.3	31.9	32.5	33.1	33.2	1.00	31.1	33.1	33.4	33.6	33.8	34.5
MSD	Mansfield	26	19.2	0.99	15.8	17.6	17.7	18.0	18.2	18.5	18.1	1.00	15.2	16.7	16.9	17.2	17.4	17.7
MWL	Morwell	66	49.5	1.00	32.5	33.2	33.7	34.4	35.1	35.9	49.5	0.99	34.4	36.3	36.7	37.0	37.4	37.9
MYT	Myrtleford	20	12.9	1.00	14.7	17.3	17.5	17.6	17.8	18.0	13.4	0.99	12.8	13.9	14.1	14.2	14.4	14.5
NLA	Newmerella	10	7.5	1.00	7.6	8.6	8.7	8.8	8.9	9.0	7.5	1.00	7.6	8.0	8.0	8.1	8.2	8.2
NRN	Narre Warren	33	48.1	1.00	18.4	16.0	16.3	16.7	17.1	17.4	38.9	0.99	21.7	22.6	22.7	22.9	23.1	23.4
OFR	Officer	66	48.8	1.00	44.3	51.7	54.5	58.2	62.2	66.0	48.6	1.00	55.8	64.0	66.8	70.4	74.1	77.7
PHI	Phillip Island	26	16.3	0.99	20.7	21.1	21.5	21.9	22.3	22.7	14.6	0.99	22.8	24.1	24.2	24.5	24.8	25.2
PHM	Pakenham	66	47.3	1.00	43.6	45.1	47.2	50.4	53.7	57.0	43.9	0.99	50.1	53.2	55.1	58.1	61.1	64.2
RUBA	Rubicon 'A'	40	30.2	0.99	10.9	12.9	13.0	13.1	13.3	13.4	30	1.00	8.7	12.2	12.2	12.3	12.4	12.5

RVE	Rowville	33	0	0.99	16.4	19.6	19.8	20.0	20.2	20.4	0	1.00	22.3	23.7	23.7	23.6	23.6	23.7
RWN	Ringwood North	66	45.2	1.00	33.9	31.6	33.9	36.3	38.8	39.4	41	0.99	37.5	42.2	44.3	46.5	48.8	49.2
RWT	Ringwood Terminal	150	95	1.00	64.6	82.3	84.0	86.0	88.2	90.3	95	1.00	88.5	105.8	106.9	108.2	109.6	111.1
SLE	Sale	60	38.7	1.00	24.3	26.3	27.4	28.6	29.8	30.2	39.7	1.00	29.3	30.8	31.8	32.9	34.0	34.2
SMG	South Morang	66	49.1	1.00	39.1	35.2	35.8	36.3	37.0	37.6	45	1.00	42.6	46.3	46.6	47.0	47.4	47.9
SMR	Seymour	66	33	1.00	30.6	33.1	33.8	34.6	35.5	36.5	33	0.99	33.1	36.2	36.8	37.4	38.2	38.9
TGN	Traralgon	60	36.7	1.00	37.8	40.3	41.2	42.2	43.3	44.5	36.2	1.00	43.5	46.9	47.4	48.0	48.9	50.1
TT	Thomastown	84	68.4	1.00	70.5	73.4	75.4	77.5	79.8	82.0	58.6	1.00	76.1	81.5	82.7	83.8	85.0	86.0
WGI	Wonthaggi	40.5	38.9	1.00	36.1	41.4	42.5	43.6	44.7	45.9	38.2	1.00	43.5	45.7	46.4	47.3	48.2	49.0
WGL	Warragul	84	70.5	1.00	60.3	60.1	62.3	64.9	68.4	71.3	61.9	0.99	68.2	71.7	73.4	76.0	79.1	81.8
WN	Wangaratta	66	43.4	1.00	40.0	40.4	41.2	42.1	43.1	43.9	37.2	0.99	44.6	47.5	48.0	48.4	49.0	49.6
WO	Wodonga	99	81.5	1.00	39.6	39.9	40.7	41.6	42.7	43.7	74.9	0.99	43.0	47.3	47.5	48.0	48.5	49.0
WOTS	Wodonga TS	70.4	50.5	0.97	33.9	34.4	35.4	36.6	38.0	39.3	44	0.71	47.5	36.9	37.7	38.6	39.6	40.6
WT	Watsonia	109	83.7	1.00	49.8	52.7	53.8	55.0	56.3	57.6	81.6	0.99	66.6	69.1	69.9	70.7	71.4	72.4
WYK	Woori Yallock	66	48.2	1.00	27.4	27.8	28.2	28.6	29.2	29.7	46.2	0.95	29.2	31.4	31.5	31.7	31.8	32.1

E.5. Minimum demand forecasts for zone substations

Table 52 - Minimum Demand Forecast for zone substations

Zone Substation	'N' Export Rating (MW)	'N-1' Export Rating (MW)	Minimum Demand (MW)	
			Actual	10% POE

			PF	2024	2025	2026	2027	2028	2029	95% Hours
BDL	-4.5	-4.2	-0.84	-8.1	-17.6	-19.9	-21.7	-22.9	-24.0	39.5
BGE	-5.4	-3.6	-0.83	-4.2	-8.6	-9.4	-9.9	-10.2	-10.5	25.0
BN	0.0	0.0	-1	-4.4	-8.8	-10.0	-10.8	-11.3	-11.8	6.75
BRA	-3.8	-2.5	0.96	1.3	-6.5	-8.2	-9.3	-10.1	-10.7	19.75
BRT	0.0	0.0	-0.42	-0.7	-2.8	-3.1	-3.5	-3.7	-3.8	71.0
BWA	0.0	0.0	-1	-1	-1.7	-1.8	-1.9	-2.0	-2.0	3.25
BWN	0.0	0.0	0.9	1.1	-4.3	-5.0	-5.6	-6.0	-6.2	43.25
BWR	-6.8	-4.5	0.86	-3.1	-9.0	-10.1	-10.8	-11.3	-11.7	10.75
CF	0.0	0.0	0.69	0.3	0.0	0.0	0.0	0.0	0.0	1.0
CLN	-41.7	-27.8	-0.94	-44.5	-79.6	-89.9	-98.7	-105.6	-111.9	24.5
CNR	-0.4	0.0	-0.87	-0.5	-1.0	-1.1	-1.2	-1.3	-1.3	1.0
CPK	-10.2	-6.8	-0.94	-4	-9.8	-11.1	-12.1	-12.8	-13.4	33.75
CRE	-10.5	-7.0	-0.98	-10.5	-22.6	-26.1	-28.7	-30.7	-32.4	3.75
CYN	-11.2	-7.4	0.88	-2.8	-8.6	-10.0	-11.0	-11.6	-12.1	14.5
DRN	-17.0	-11.3	-0.98	-21.1	-33.4	-36.9	-39.7	-41.6	-43.3	26.75
ELM	-14.8	-9.9	-0.67	-5.1	-14.4	-16.7	-18.4	-19.6	-20.5	59.75
EPG	-4.0	-2.6	0.07	0.1	-31.9	-36.3	-39.8	-42.4	-44.6	104.75
FGY	0.0	0.0	-0.9	-4.6	-10.4	-11.4	-12.0	-12.4	-12.7	5.25
FTR	0.0	0.0	0.81	-2.2	-4.8	-5.4	-6.0	-6.3	-6.6	1.25
HPK	-24.7	-16.5	-0.99	-24.7	-38.6	-41.4	-43.6	-45.2	-46.3	18.0
KLK	-0.2	-0.1	-0.71	-1.3	-2.4	-2.6	-2.8	-2.9	-3.0	18.25
KLO	-25.8	-17.2	-0.98	-27.6	-48.7	-55.0	-61.1	-66.8	-72.3	26.0
KMS	0.0	0.0	-0.89	-2.3	-5.3	-6.0	-6.7	-7.1	-7.6	23.75
LDL	-4.6	-3.1	-0.69	0.1	-6.9	-8.3	-9.5	-10.3	-10.9	62.0
LGA	0.0	0.0	0.69	0.3	-5.8	-6.8	-7.6	-8.1	-8.6	13.0

LLG	0.0	0.0	-1	-1.8	-4.6	-5.4	-6.0	-6.4	-6.8	0.0
LYD	-4.6	0.0	-0.99	-4.6	-7.7	-8.5	-9.1	-9.5	-9.8	28.5
MBY	0.0	0.0	-0.32	-1	-2.0	-2.2	-2.3	-2.5	-2.5	55.75
MDI	0.0	0.0	0.01	0	0.0	0.0	0.0	0.0	0.0	541.5
MFA	-3.5	-2.3	1	-5.1	-9.0	-9.8	-10.4	-10.8	-11.1	8.0
MJG	0.0	0.0	0	0.1	0.4	0.3	0.3	0.3	0.2	402.5
MOE	-3.1	-2.1	-0.81	-7.6	-13.2	-14.2	-15.0	-15.5	-15.9	27.0
MSD	0.0	0.0	-1	-3.8	-7.4	-8.2	-9.0	-9.5	-10.0	59.5
MWL	0.0	0.0	0.36	0.4	-3.8	-4.8	-5.5	-6.0	-6.4	12.75
MYT	-0.3	-0.2	-0.98	-2.8	-5.0	-5.7	-6.2	-6.6	-6.9	39.75
NLA	-0.5	-0.3	0.87	-1.7	-3.3	-3.6	-3.9	-4.1	-4.3	43.5
NRN	-5.3	0.0	0.98	0.5	-2.1	-2.4	-2.7	-2.8	-2.9	27.75
OFR	-13.6	-9.1	-0.96	-12.5	-26.9	-30.6	-33.5	-35.7	-37.7	19.5
PHI	-2.8	-2.8	-0.44	-7.2	-11.1	-12.1	-12.9	-13.4	-13.9	1.25
PHM	-10.2	-6.8	-0.96	-5.6	-12.6	-14.2	-15.5	-16.4	-17.1	15.25
RUBA	-0.5	-0.4	-1	-3.6	-6.4	-6.8	-7.1	-7.3	-7.5	24.0
RVE	-1.7	0.0	-0.93	-4.6	-8.2	-9.0	-9.7	-10.1	-10.5	15.0
RWN	-10.7	-7.1	-0.93	-3.6	-7.9	-9.1	-9.9	-10.5	-10.9	49.25
RWT	0.0	0.0	0.99	6.7	1.9	1.3	0.9	0.8	0.9	20.25
SLE	-6.8	-4.5	-0.72	-2	-6.2	-7.2	-7.9	-8.4	-8.9	15.25
SMG	-1.4	-0.9	0.35	1.1	-3.6	-4.5	-5.2	-5.6	-5.9	40.25
SMR	-0.1	0.0	-0.28	-1.4	-5.7	-6.8	-7.7	-8.3	-8.8	18.5
TGN	-2.0	-1.3	-1	-4.9	-12.3	-14.1	-15.7	-16.8	-17.6	17.75
TT	0.0	0.0	-0.77	2.7	-0.8	-1.4	-1.8	-2.0	-2.1	12.0
WGI	-9.9	-9.9	-1	-20.4	-30.1	-32.2	-34.0	-35.3	-36.4	4.5
WGL	0.0	0.0	0.42	-2.9	-13.6	-16.2	-18.2	-19.6	-20.8	22.25
WN	-6.7	-6.6	-0.98	-8.9	-16.7	-18.6	-20.2	-21.4	-22.3	21.0

WO	0.0	0.0	0	0	-6.6	-8.0	-9.1	-9.9	-10.4	186.5
WOTS	-6.4	-4.3	-0.72	-8.2	-31.4	-34.5	-36.8	-38.3	-39.4	8.0
WT	0.0	0.0	1	3.6	-2.3	-3.6	-4.5	-5.1	-5.5	1.75
WYK	-3.9	-2.6	-0.85	-3.9	-7.8	-8.8	-9.6	-10.2	-10.6	37.45

E.6. Additional import-related Information for zone substations

Table 53 - Additional Import-Related Information – Winter and Summer

			Winter				Summer			
ZSS	Name	Name Plate Rating (MVA)	Firm Capacity Winter (MVA)	Load Transfer Capacity (MVA)	Embedded Generation Capacity (MVA)	Estimated Hours at 95% of Peak Load	Firm Capacity Summer (MVA)	Load Transfer Capacity (MVA)	Embedded Generation Capacity (MVA)	Estimated Hours at 95% of Peak Load
BDL	Bairnsdale	81.0	95.2	3.5	0	5.00	88.0	3.5	0	1.6
BGE	Belgrave	66.0	47.3	16.4	3.8	5.00	40.4	16.4	3.8	0.6
BN	Benalla	40.5	36.8	1.6	0.15	3.0	30.7	1.6	0.15	4.4
BRA	Boronia	99.0	86.1	26.5	2.0	8.0	77.8	26.5	2.0	1.6
BRT	Bright	40.0	30.0	2.0	0.0	1.5	27.9	2.0	0.0	4.1
BWA	Barnawatha	33.0	0.0	7.1	5.0	2.3	0.0	7.1	5.0	1.9
BWN	Berwick North	33.0	48.1	30.1	0.0	0.3	38.9	30.1	0.0	0.0

BWR	Bayswater	81.0	78.6	24.0	0.0	7.5	66.2	24.0	0.0	0.3
CF	Clover Flat	10.0	7.3	0.0	0.0	4.8	6.7	0.0	0.0	6.3
CLN	Clyde North	66.0	47.8	26.5	0.0	2.3	43.5	26.5	0.0	1.9
CNR	Cann River	10.0	0.0	3.0	2.0	6.0	0.0	3.0	2.0	0.0
CPK	Chirnside Park	66.0	48.6	23.0	1.3	3.8	48.8	23.0	1.3	2.8
CRE	Cranbourne	66.0	46.3	21.8	0.0	2.3	41.1	21.8	0.0	0.6
CYN	Croydon	99.0	94.0	34.8	0.0	6.8	83.0	34.8	0.0	1.3
DRN	Doreen	66.0	49.1	20.7	8.8	3.3	45.9	20.7	8.8	1.3
ELM	Eltham	99.0	89.1	23.8	0.0	5.0	80.7	23.8	0.0	4.4
EPG	Epping	99.0	92.4	14.1	2.0	18.3	82.0	14.1	2.0	1.3
FGY	Ferntree Gully	93.0	67.4	20.2	0.0	3.8	61.8	20.2	0.0	2.2
FTR	Foster	66.0	49.0	3.0	0.0	3.3	49.1	3.0	0.0	0.6
HPK	Hampton Park	99.0	90.7	14.2	8.8	7.3	81.6	14.2	8.8	1.3
KLK	Kinglake	10.0	7.4	1.0	0.0	12.5	7.4	1.0	0.0	2.2
KLO	Kalkallo	66.0	49.1	12.6	0.0	7.5	49.1	12.6	0.0	0.9
KMS	Kilmore South	30.0	14.5	5.2	0.0	8.5	16.6	5.2	0.0	2.5
LDL	Lilydale	99.0	96.9	17.7	2.3	16.3	90.1	17.7	2.3	1.9
LGA	Leongatha	73.0	41.6	3.0	1.8	4.8	41.5	3.0	1.8	2.5

LLG	Lang Lang	33.0	0.0	23.6	0.0	7.0	0.0	23.6	0.0	1.3
LYD	Lysterfield	33.0	0.0	24.6	0.2	4.0	0.0	24.6	0.2	0.9
MBY	Mt Beauty	30.0	21.4	3.5	0.0	1.3	19.9	3.5	0.0	3.2
MDI	Murrindindi	0.5	0.0	0.0	0.0	1.5	0.0	0.0	0.0	0.3
MFA	Maffra	40.0	37.8	6.5	0.0	0.5	31.1	6.5	0.0	0.5
MJG	Merrijig	20.0	0.0	9.0	3.8	2.8	0.0	9.0	3.8	1.3
MOE	Moe	40.5	36.3	4.3	10.8	4.3	33.2	4.3	10.8	3.8
MSD	Mansfield	26.0	19.2	1.5	0.0	1.8	18.1	1.5	0.0	1.9
MWL	Morwell	66.0	49.5	8.0	1.5	15.8	49.5	8.0	1.5	1.9
MYT	Myrtleford	20.0	12.9	1.6	0.0	8.0	13.4	1.6	0.0	2.8
NLA	Newmerella	10.0	7.5	3.2	0.0	6.0	7.5	3.2	0.0	0.9
NRN	Narre Warren	33.0	48.1	29.8	0.0	0.3	38.9	29.8	0.0	0.0
OFR	Officer	66.0	48.8	13.5	0.0	1.5	48.6	13.5	0.0	1.6
PHI	Phillip Island	26.0	16.3	6.0	5.0	3.5	14.6	6.0	5.0	0.0
PHM	Pakenham	66.0	47.3	20.2	0.0	9.8	43.9	20.2	0.0	0.9
RUBA	Rubicon 'A'	40.0	30.2	0.5	19.9	5.3	30.0	0.5	19.9	2.8
RVE	Rowville	33.0	0.0	34.4	0.0	9.8	0.0	34.4	0.0	0.9
RWN	Ringwood North	66.0	45.2	13.9	0.0	7.8	41.0	13.9	0.0	3.8
RWT	Ringwood Terminal	150.0	95.0	16.3	0.0	7.8	95.0	16.3	0.0	3.8
SLE	Sale	60.0	38.7	2.5	0.0	4.0	39.7	2.5	0.0	1.3

SMG	South Morang	66.0	49.1	17.4	1.5	1.0	45.0	17.4	1.5	1.9
SMR	Seymour	66.0	49.5	4.5	0.0	6.0	46.9	4.5	0.0	1.3
TGN	Traralgon	60.0	36.7	9.7	10.0	2.0	36.2	9.7	10.0	1.6
TT	Thomastown	84.0	68.4	20.7	6.9	9.3	58.6	20.7	6.9	1.9
WGI	Wonthaggi	40.5	38.9	4.0	0.0	2.5	38.2	4.0	0.0	0.6
WGL	Warragul	84.0	70.5	3.2	12.0	2.3	61.9	3.2	12.0	0.6
WN	Wangaratta	66.0	43.4	4.3	0.0	3.5	37.2	4.3	0.0	3.8
WO	Wodonga	99.0	81.5	3.5	2.0	3.3	74.9	3.5	2.0	1.3
WOTS	Wodonga Terminal	70.4	50.5	2.0	10.2	3.3	44.0	2.0	10.2	3.8
WT	Watsonia	109.0	83.7	20.6	0.0	7.3	81.6	20.6	0.0	1.3
WYK	Woori Yallock	66.0	48.2	0.0	0.9	1.5	46.2	0.0	0.9	1.6

F. System Strength Locational Factors and Corresponding Nodes

Table 54 provides the system strength locational factor (SSLF) for each system strength connection point for which AusNet is the Network Service Provider and the corresponding system strength node as required by schedule 5.8 (q) of the NER. The SSLFs have been calculated as per the AEMO System Strength Impact Assessment Guidelines[33]. These values are subject to change and may differ to those provided to proponents during the connection process.

Table 54: System Strength Locational Factors and Corresponding System Strength Nodes

Zone Substation	Voltage (kV)	System Strength Locational Factor	System Strength Node[34]
BDL	66	1.4932	Hazelwood
BDL	22	1.6863	Hazelwood
BDSS	66	1.4433	Hazelwood
BGE	66	1.1337	Thomastown
BGE	22	1.3795	Thomastown
BN	66	1.1471	Dederang
BN	22	1.4751	Dederang
BRA	66	1.0886	Thomastown
BRA	22	1.2557	Thomastown
BRT	66	1.3338	Dederang
BRT	22	1.6686	Dederang
BWA	66	1.3265	Dederang
BWA	22	1.8379	Dederang
BWN	66	1.1415	Thomastown
BWN	22	1.6527	Thomastown
BWR	66	1.0767	Thomastown
BWR	22	1.2286	Thomastown
CF	66	1.3101	Dederang
CF	22	1.9786	Dederang
CLN	66	1.0716	Thomastown
CLN	22	1.3144	Thomastown
CNR	66	3.1304	Hazelwood

[33] System Strength Impact Assessment Guidelines, AEMO, July 2024

[34] 2023 System Strength Report, AEMO, December 2023

Zone Substation	Voltage (kV)	System Strength Locational Factor	System Strength Node[34]
CNR	22	3.9928	Hazelwood
CPK	66	1.0973	Thomastown
CPK	22	1.3483	Thomastown
CRE	22	1.3009	Thomastown
CYN	66	1.0900	Thomastown
CYN	22	1.2539	Thomastown
DME	66	1.2361	Dederang
DRN	66	1.0750	Thomastown
DRN	22	1.3220	Thomastown
ELM	66	1.0711	Thomastown
ELM	22	1.2279	Thomastown
EPG	66	1.0712	Thomastown
EPG	22	1.2371	Thomastown
FGY	66	1.1234	Thomastown
FGY	22	1.2844	Thomastown
FTR	66	1.3044	Hazelwood
FTR	22	1.5470	Hazelwood
HPK	66	1.1015	Thomastown
HPK	22	1.2648	Thomastown
KLK	66	1.1671	Thomastown
KLK	22	1.7142	Thomastown
KLO	66	1.1443	Thomastown
KLO	22	1.3996	Thomastown
KMS	66	1.2452	Thomastown
KMS	22	1.9482	Thomastown
LDL	66	1.1101	Thomastown
LDL	22	1.2769	Thomastown
LGA	66	1.2108	Hazelwood
LGA	22	1.4458	Hazelwood
LLG	66	1.1502	Thomastown

LLG	22	1.8494	Thomastown
LSSS	66	1.3409	Hazelwood

Zone Substation	Voltage (kV)	System Strength Locational Factor	System Strength Node[34]
LYD	66	1.1242	Thomastown
LYD	22	1.6239	Thomastown
MBY	66	1.2352	Dederang
MBY	22	1.9505	Dederang
MDI	66	1.2848	Thomastown
MDI	22	1.3351	Thomastown
MFA	66	1.2586	Hazelwood
MFA	22	1.6878	Hazelwood
MJG	66	1.9695	Dederang
MJG	22	2.6003	Dederang
MOE	66	1.1037	Hazelwood
MOE	22	1.4269	Hazelwood
MSD	66	1.7502	Dederang
MSD	22	2.1886	Dederang
MWL	22	1.3696	Hazelwood
MYT	66	1.3801	Dederang
MYT	22	1.8508	Dederang
NLA	66	2.4726	Hazelwood
NLA	22	3.3034	Hazelwood
NRN	66	1.1299	Thomastown
NRN	22	1.6361	Thomastown
OFR	66	1.1462	Thomastown
OFR	22	1.3871	Thomastown
PHI	66	1.7377	Hazelwood
PHI	22	2.2038	Hazelwood
PHM	66	1.1276	Thomastown
PHM	22	1.3736	Thomastown
RUBA	66	1.3674	Thomastown

RUBA	22	1.6944	Thomastown
RVE	22	1.6826	Thomastown
RWN	66	1.0982	Thomastown
RWN	22	1.3050	Thomastown

Zone Substation	Voltage (kV)	System Strength Locational Factor	System Strength Node[34]
SLE	66	1.2997	Hazelwood
SLE	22	1.5384	Hazelwood
SLF	66	1.2215	Thomastown
SMG	66	1.0520	Thomastown
SMG	22	1.3566	Thomastown
SMR	66	1.4491	Thomastown
SMR	22	1.6805	Thomastown
TGN	66	1.1239	Hazelwood
TGN	22	1.3635	Hazelwood
TT	66	1.0546	Thomastown
TT	22	1.2820	Thomastown
WGI	66	1.3836	Hazelwood
WGI	22	1.7028	Hazelwood
WGL	66	1.1845	Hazelwood
WGL	22	1.3381	Hazelwood
WN	66	1.1561	Dederang
WN	22	1.4042	Dederang
WO	66	1.1735	Dederang
WO	22	1.3426	Dederang
WOTS22	22	1.2585	Dederang
WT	66	1.0931	Thomastown
WT	22	1.4024	Thomastown
WYK	66	1.2606	Thomastown
WYK	22	1.4348	Thomastown
YEA	66	1.4763	Thomastown

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