Augmentation

AMS – Electricity Distribution Network

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Table of Contents

1 Executive Summary

This Asset Management Strategy is central to AusNet Services' processes for managing the electricity distribution assets, determining the delivery of quality services to customers and value to shareholders. It summarises the proposed augmentations works within the 2022-26 Electricity Distribution Price Review (EDPR) period to ensure that AusNet Services achieves its regulatory and business performance targets.

The AMS is underpinned by the regulatory and commercial imperatives of delivering efficient cost and service performance. It recognises that cost and service efficiency does not mean lowest possible cost, nor does it mean guaranteed reliability. Instead, efficiency requires the costs and benefits of all expenditure decisions to be weighed against one another. A key element in this cost benefit analysis is the consideration of risk management in relation to asset performance and network reliability.

AusNet Services' ongoing commitment to maintain ISO 55001 Asset Management accreditation ensures an auditable asset management system facilitating customer's expectations to safely maintain the quality, reliability and security of supply in an economic manner.

AusNet Services welcomes feedback from stakeholders on this document.

2 Introduction

2.1 Purpose

This document describes AusNet Services' plans to augment[1] its distribution network over the period to mid 2026.

This document forms part of the Asset Management System and should be considered in conjunction with other related documents; particularly the *Distribution Annual Planning Report* (DAPR), *AMS 20-16 Distribution Network Planning Standards and Guidelines* and *AMS 20-35 Network Support Services*.

2.2 Scope

This document covers all network augmentation work on the electricity distribution network, excluding customer-initiated work.

2.3 Asset Management Objectives

As stated in *AMS 01-01 Asset Management System Overview*, the high-level asset management objectives are:

- Comply with legal and contractual obligations;
- Maintain safety;
- Be future ready;
- Maintain network performance at the lowest sustainable cost; and
- Meet customer needs.

As stated in *AMS 20-01 Electricity Distribution Network Asset Management Strategy*, the electricity distribution network objectives are:

- Improve efficiency of network investments;
- Maintain long-term network reliability;
- Implement REFCLs within prescribed timeframes;
- Reduce risks in highest bushfire risk areas;
- Achieve top quartile operational efficiency; and
- Prepare for changing network usage.

[1] Augmentation has the meaning prescribed in the NER and also includes work relating to improving the quality of the network, for example, to meet regulatory obligations.

3 Network Description

3.1 Connection Points

AusNet Services' distribution network is supplied from fourteen transmission connection points, known as transmission node identities (TNIs). These connection points are on the low-voltage side of the terminal stations, and provide electricity at 66kV, 22kV and 11kV. There are eleven 66kV connection points, two 22kV connection points, and one 11kV connection point supplying AusNet Services' distribution network.

3.2 Sub-transmission System

AusNet Services' sub-transmission system comprises more than 100 individual circuits that are predominantly configured as loops back to the terminal station to maximise reliability. The sub-transmission network supplies electricity to zone substations that transform the voltage for distribution in the surrounding area.

The urban lines are relatively short and are often constructed with 37/3.75 AAC conductor with a high rating of typically 1025 A (117 MVA). They supply zone substations that are usually configured in a loop with loading well within ratings under system normal conditions. These lines can be subject to high loading following a network contingency. Network limitations are usually due to the thermal ratings of the urban 66 kV lines.

The lines in rural areas have a variety of configurations ranging from radial to complex multi-line systems. They are usually much longer and have a variety of ratings depending on conductor types and maximum operating temperatures, typically around 500 A (57 MVA). These lines are well within ratings for system normal conditions but can be subjected to high loadings during a network contingency. Network limitations are often due to the thermal rating of assets, but can also result from the excessive voltage drop that is often experienced on long rural systems. Voltage collapse can occur for outages of 66 kV lines during high loading times.

3.3 Zone Substations

The 22kV distribution network is currently supplied by 57 zone and switching stations, which are strategically located close to regional load centres. Additionally, three terminal stations also supply 22kV distribution feeders, and three 22/6.6kV zone substations supply the Mount Dandenong area via three 6.6kV feeders. These stations supply approximately 730,000 customers.

The substations are all loaded such that at maximum demand, and with all plant in service, transformers are not loaded above their cyclic ratings. Many of the zone substations are loaded above the N-1 rating at maximum demand (i.e. above the rating with one transformer out of service).

If a transformer outage occurs when loading is above the N-1 rating, load will be shed to ensure the loading is maintained within cyclic ratings. Transformers will not be operated above their cyclic ratings due to the risks of asset damage, further failure and the serious customer impact resulting from the simultaneous unavailability of multiple transformers.

3.4 Distribution Feeders

AusNet Services currently has 348 22 kV distribution feeders and eight 6.6 kV feeders supplying the Mt Dandenong area.

Feeders in urban areas usually have 'backbones' constructed using 240 mm^2 or 185 mm^2 aluminium or 150 mm^2 copper cables and 6/1/.186 ACSR or 19/3.25 AAC overhead lines. These lines were designed and constructed over many years and are intended for operation at maximum temperatures of either 50°C or 65°C, generally giving a rating of between 180 and 375 A.

Feeders in urban areas are usually 'urban' or 'short rural' types and seldom have a backbone length of more than 10 km and as a result they are limited only by the thermal rating of the conductors.

Feeders in rural areas have a greater range of conductor sizes, often smaller than the urban areas with conductors as small as 3/2.75 steel conductor at the extremities, and usually designed to 50°C operation. In some cases thermal ratings are below 100 A, but can be as high as typical urban ratings.

The length of rural feeders means that voltage drop, as well as thermal rating, often limits the load current capacities of these feeders.

3.5 SWER Systems

There are over 500 Single Wire Earth Return (SWER) systems in the network, which are supplied from the 22 kV distribution system via SWER isolating transformers. The standard capacities of SWER transformers are 25, 50, 100 and 200 kVA, with the majority in the range between 25 kVA and 100 kVA.

Customers are supplied from 5, 10, 20, 25 kVA SWER distribution transformers. Most of these transformers are not fitted with off-load tap-changers. SWER systems are constructed mainly with 3/2.75 steel conductors.

Over the past 30 years, customer numbers and demand has increased significantly in the SWER network, overloading a number of these SWER systems.

Whilst the standard supply agreement is 6 kVA, some customers in the SWER system connect loads in excess of this limit, such as floor heating (15 to 40 kW), air conditioners and hot-waters systems. Medium-sized dairy farms in rural areas with demand in excess of 25 kVA (25–60 kVA) are also supplied from these SWER systems.

To provide additional capacity, some domestic and farming customers have been supplied via two 20 kVA or two 25 kVA SWER distribution transformers in parallel to meet their electricity demands. In one instance, a dairy farm has been supplied via three 20 kVA distribution transformers in parallel.

3.6 Distribution Substations and Low Voltage Networks

AusNet Services has over 60,000 distribution substations; the vast majority are 22 kV/415 V, some are 6.6 kV/415 V and some are SWER system isolating transformers.

LV networks are installed as underground cable in the new developing residential areas in Melbourne and towns in rural areas. In rural areas away from towns, LV circuits are avoided by installing small distribution substations for each customer. Underground cables are generously sized to avoid very costly upgrades to underground mains.

3.7 Rapid Earth Fault Current Limiters (REFCL)

The 2009 Victorian Bushfire Royal Commission made several recommendations with respect to fires initiated from distribution electricity networks. Subsequently, the Victorian Government established the Powerline Bushfire Safety Program to research the optimal way to deploy Rapid Earth Fault Current Limiters (REFCL) for bushfire prevention.

This research led the Government to introduce new regulations, the *Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016*, which require AusNet Services to install REFCL technology in twenty-two nominated zone substations. A REFCL is a protection device that is installed on the zone substation transformer neutral and reduces the risk of fires caused by power lines. It does this by rapidly limiting the energy that is released in certain types of power line faults, known as earth faults. As such the REFCL device protects the 22kV network from single phase to earth faults.

The dates for compliance are separated into three tranches based on a prioritising points system, and occur on 1 May 2019, 1 May 2021 and 1 May 2023. In addition, the Victorian Government has enforced timely compliance of the Regulations by introducing significant financial penalties though the Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme) Act 2017 (the Act).

4 Augmentation Drivers

4.1 Regulatory Requirements

4.1.1 Planning Requirements

The National Electricity Rules (NER) Clause 5.13 *Distribution annual planning process* outlines the requirements for Distribution Network Service Providers (DNSPs) to undertake an annual planning review to identify capacity limitations on its network and to identify whether corrective action is necessary to address system limitations.

Further, Clause 5.14 *Joint planning* places an obligation on DNSPs to carry out joint planning with other Transmission and Distribution Network Service Providers for connection points.

The Electricity Distribution Licence issued to AusNet Electricity Services Pty Ltd requires AusNet Services to provide network capacity to connect customers and, where necessary, to augment the network to provide that capacity.

The Electricity Distribution Code requires AusNet Services to develop and implement plans that ensure the network supplies electricity that meets prescribed levels of:

1. Quality of supply (Clause 4);
2. Reliability of supply (Clause 5); and
3. Guaranteed service levels (Clause 6).

Clause 4 *Quality of supply* specifies requirements relating to:

- Supply frequency;
- Voltage level;
- Power factor;
- Inductive interference;
- Negative sequence voltage;
- Load balance;
- Disturbing loads; and
- Monitoring of quality of supply.

Clause 5 *Reliability of supply* specifies requirements relating to:

- Distributor’s targets;
- Reliability of supply;
- A distributor’s right to interrupt supply;
- Unplanned interruptions;
- Planned interruptions;
- Special needs; and
- Informing Government Departments.

Clause 6 *Guaranteed service levels* specifies the minimum service levels required to be provided by distribution business and covers:

- Appointments;

- Failure to supply;
- Supply restoration and low reliability payments; and
- Time for payment.

Customer requirements for network capacity are established through Connection Applications, the Annual Planning Process and through ongoing monitoring of network loads, particularly at times of peak demand.

Secondary means of determining customer requirements are through network overload faults and customer complaints relating to quality and reliability of supply.

4.1.2 Voltage Compliance

The Electricity Distribution Code regulates the distribution of electricity by a distributor to its customers. Clause 4 details the regulatory obligations for the quality of supply for a number of parameters, including voltage.

Clause 4.2.1 of the Electricity Distirbution Code states that:

> *a distributor must maintain a nominal voltate level at the point of supply to the customer's electrical installation in accordance with the Electrical Safety (Network Assets) Regulations 1999*[2] *or, if these reguations do not apply to the distributor, at one of the following standard nominal voltages:*
>
> *(a) 230V;*
>
> *(b) 400V*
>
> *(c) 460V*
>
> *(d) 6.6kV*
>
> *(e) 11kV*
>
> *(f) 22kV; or*
>
> *(g) 66kV*

Table 1 is reproduced from the Electricity Distribution Code and lists the variations from the relevant standard nominal voltage allowed.

[2] This Subordinate Law was repealed on 8 December 2009 by the Electricity Safety (Installations) Regulations 2009

Table 1: Standard Nominal Voltage Variations

<table>
<tr><th colspan="5">STANDARD NOMINAL VOLTAGE VARIATIONS</th></tr>
<tr><th rowspan="2">Voltage Level in kV</th><th colspan="3">Voltage Range for Time Periods</th><th rowspan="2">Impulse Voltage</th></tr>
<tr><th>Steady State</th><th>Less than 1 minute</th><th>Less than 10 seconds</th></tr>
<tr><td>< 1.0</td><td>+10%
- 6%</td><td>+14%
- 10%</td><td>Phase to Earth +50%-100%
Phase to Phase +20%-100%</td><td>6 kV peak</td></tr>
<tr><td>1-6.6</td><td rowspan="3">± 6 %
(± 10 %
Rural Areas)</td><td rowspan="3">± 10%</td><td rowspan="3">Phase to Earth +80%-100%
Phase to Phase +20%-100%</td><td>60 kV peak</td></tr>
<tr><td>11</td><td>95 kV peak</td></tr>
<tr><td>22</td><td>150 kV peak</td></tr>
<tr><td>66</td><td>± 10%</td><td>± 15%</td><td>Phase to Earth +50%-100%
Phase to Phase +20%-100%</td><td>325 kV peak</td></tr>
</table>

Thus, the steady state voltage limits are given in Table 2.

Table 2: Steady State Voltage Limits

Nominal Voltage	Minimum Steady State Voltage	Maximum Steady State Voltage
Low voltage	216V	253V
22kV – Urban	20.7kV	23.3kV
22kV – Rural	19.8kV	24.2kV
66kV	59.4kV	72.6kV

Whilst not referenced in any regulations *AS 61000.3.100 Electromagnetic compatibility (EMC) – Part 3.100: Limits – Steady state voltage limits in public electricity systems* acknowledges that achieving 100% compliance to hundreds of thousands of customer connections spread over a large geographical area at all times is not economically nor practically possible and proposes minimum compliance levels for network-wide compliance.

AusNet Services terms compliance to this standard as 'functional' compliance.

4.1.3 Low Voltage Protection

The Electricity Safety (General) Regulations 2019 introduced a requirement for distributors to install LV circuit breakers in substations with direct connect customers. This is a step change from current practice which relies solely on HV protection. The additional work is estimated to cost [C.I.C] per year for 25 sites at [C.I.C] per site.

4.2 Technical Planning Criteria and Planning Standards

The following items are considered in planning network capability:

- Ratings;
- Voltage levels;
- Quality of supply;
- Reliability of supply;
- New connections to the network;
- Fault levels; and
- Phase angle.

4.2.1 Ratings

One of the main considerations when planning for the capability of a network is the rating of network elements. Network elements will be designed for a maximum operating temperature and this limits their capability to a maximum load.

Ratings will depend on ambient temperature and both summer and winter ratings will be defined but it is the summer limitation that usually is the most critical.

Ratings for transformers are based on maximum operating temperature as specified in AS/NZS 60076.7:2013 *Power transformers – Loading guide for oil-immersed power transformers*.

Ratings for overhead lines are based on maximum operating temperatures and minimum clearances as specified in AS/NZS 7000 *Overhead line design*.

Ratings for underground cables are based on maximum operating temperatures and are specified in the Underground Cable Design Manual. Ratings for transformers are based on maximum operating temperature and a manufacturer's continuous rating. Cyclic ratings which recognise a peak demand rating in a varying load cycle are calculated for cables and transformers. Ratings for other equipment would be as defined by manufacturer's recommendations and specifications.

Further details on plant specific rating considerations can be found in AMS 20-16 *Distribution Network Planning Standards and Guidelines*.

4.2.2 Voltage Levels

The other major consideration in planning network capability is maintaining suitable voltage levels. Based on the Electricity Distirbution Code, the allowable range for steady state voltage in the low vaoltage network is 216 V to 253 V. Voltages outside the steady state limits may cause equipment damage and reduced life spans across lines in the distribution network.

AusNet Services' distribution network has a broad range of voltage related challenges. Much of the network is in rural areas supplied by long lines where voltage drop is a critical issue. Line voltage regulators are used on both the 22kV and 66kV networks to help maintain voltages levels. Voltage collapse can occur in some parts of the 66 kV sub-transmission network if a network fault occurs during the peak demand periods. In manner cases network augmentation is not economically feasible to mitigate this voltage collapse risk.

Conversely, with the increased uptake of distributed energy resources, such solar PV generation, pushing up voltage levels, many customer are experiencing more frequent high voltages, as described in Sections 5.2 and 7.7.

Further details on specific voltage compliance considerations can be found in AMS 20-16 *Distribution Network Planning Standards and Guidelines*.

4.3 REFCL Compliance

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

1. Electricity Safety Act 1998; and
2. 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:

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

Where:

R_f (fault resistance) is legislated to 25.4kΩ

U_{ph} (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

I_{CE} (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 30mA). • 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 level. • In general and from a forward planning perspective should not be more than 100A, although the actual limit is location specific because it is affected 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.

5 Other Factors

5.1 Network Support Solutions

Demand side management and embedded generation (EG) are considered as non-network solutions to either defer network augmentation projects or to reduce the level of energy at risk on the network where network augmentation is not economic.

Clause 5.13.1 of the National Electricity Rules describes the demand side engagement obligations of a DNSP as part of the distribution annual planning review. AusNet Services publishes a Demand Side Engagement Strategy and maintains a demand side engagement register, to which interested parties can be added to be notified of developments relating to distribution network planning and expansion, including non-network support opportunities.

AMS 20-35 Network Support Services outlines the application of demand management in addressing network capacity requirements.

For network overload constraints, a non-network solution such as deploying or engaging embedded generation or demand side services is generally most economic to defer network augmentation and capital expenditure when:

- demand growth rates are low or uncertain;
- the amount of load curtailment required is small relative to the overall load;
- the duration of the peak demand period is relatively short; or
- the most economic network augmentation is expensive.

These conditions more typically arise on rural feeders or in networks that supply holiday destinations. However, as detailed in Section 6.2.3, there is currently very few network limitations currently forecast on rural feeders. Instead, the bulk of forecast feeder limitations are in the urban growth corridors where demand growth is strong and network augmentation costs are generally lower due to the relatively confined geographic area of network requiring augmentation.

While there are few clear opportunities currently available for network support options, a recent example where network support has deferred a costly augmentation is feeder BN1, which supplies the rural town of Euroa from Benalla Zone Substation. BN1 is a long feeder that would have required an expensive network augmentation to supply its summer peak demand if a network support option wasn't deployed. Instead of undertaken a network augmentation, for many years AusNet Services has deployed mobile diesel generation over summer to bolster the supply capacity of the network during the peak demand periods.

Where a feeder supplies sufficient commercial and industrial (C&I) customer demand, network support contracts with C&I customers for load curtailment can be used to reduce feeder load during high demand periods and potentially defer network augmentation. While there is currently less opportunity to deploy demand management services at the residential level due to a lack of load controllability, initiatives that allow for direct load control (DLC) of demand response enabled devices (DREDs), such as air conditions and pool pumps, have been investigated and will increasingly be deployed as technology prices continue to reduce and more residential customers invest in control capable devices.

For condition-based retirement and replacement projects, the value of expected unserved energy is more generally driven by the unreliability of assets than a forecast increase in asset utilisation. Non-network support options are often less suited in these situations because the network support capacity and energy required to avoid an asset replacement is generally much larger than that required to meet slow growing demand.

While network support options are often very targeted, they can also take the form of broad-based initiatives that act across a large proportion of the network. Rather than targeting specific areas of risk or constraint, these initiatives are expected to produce customer benefits over the longer-term, but not necessarily within a single regulatory period, and cannot typically be tied to the provision of capacity at a specific network location. Some broad-based initiatives that AusNet Services pursues include:

- Critical Peak Demand (CPD) based tariffs for large customers. Customers with an annual consumption greater than 160 MWh that are on tariffs that include a critical peak demand (CPD) component. This CPD charge provides a significant pricing signal to customers to reduce their demand over five nominated critical peak demand days in each summer period (1 December to 31 March).
- The Good Grid Program, where residential customers are compensated for reducing their energy usage for up to ten days and four hours during the summer period.

5.2 Impact of Solar on the Electricity Distribution Network

In a traditional electricity network, with no distributed generation installed on the distribution network, as the load on a distribution line and distance from the zone substation increased, the voltage level along the line decreased. This meant that the voltage levels at the zone substation end of distribution lines were typically set at close to the top of the allowable voltage band, allowing the voltage level to drop along the distance of the distribution line (Figure 1).

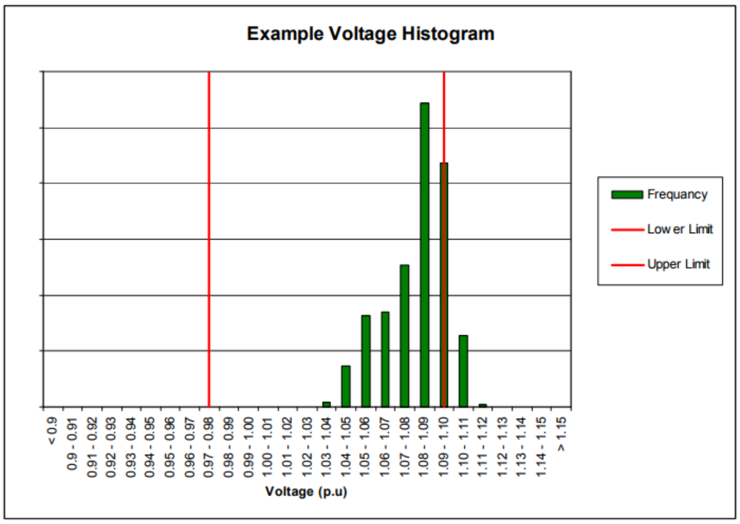

Figure 1: Example of a typical voltage histogram

This situation is changing with customers installing rooftop solar systems.

When a customer with a solar installation is producing more power than they can use within their premise, they export the excess power into the electricity distribution network. In order for a solar inverter to export power to the electricity distribution network, it must put out a higher voltage than the network to force it back.

AS 4777.1 says that the maximum voltage rise in a solar installation must be 2% of 230V (4.6V).

This means that in a system which has the voltage biased towards the top of the allowable voltage range, rooftop solar may increase the voltage to the point that it is outside the allowable range.

For example, if the electricity distribution network has a steady state voltage at the top of the compliant range at 253V, on a good solar day when no one is at home, the solar installation will be at full export and the voltage may be raised to 253 + 4.6 = 257.6V. In this instance, this would result in the solar inverter tripping off on overvoltage. Once the inverter has tripped off the voltage will return to within the compliant range and the solar inverter will turn on again, raising the voltage and potentially tripping again in 10 minutes. This type of operation will potentially shorten the life of the solar inverter.

5.3 Victorian Government Solar Homes Program

Leading up to the Victorian state election in November 2018, the state government made multiple election commitments relating to the Solar Homes program. Roll-out of the Victorian State Solar Homes Program has since commenced, and the design includes the following rebates:

- Solar PV rebate for 650,000 homes
- Solar PV rebate for 50,000 rental properties
- Solar hot water rebate for 60,000 homes
- Battery rebate for 10,000 homes

According to the Solar Victoria website (www.solar.vic.gov.au), the Solar Homes package currently includes two rebates for the installation of solar PV or solar hot water to eligible householders.

The Solar Homes program consists of half price solar panels for up to 650,000 eligible households. This is in addition to the existing approximately 350,000 solar systems already installed in Victoria. Accordingly, AusNet Services expects, and has recently experienced, this subsidy to lead to a significant increase in solar panel installations within its network area.

Figure 2 shows the forecast uptake of distributed energy resources (DER) within AusNet Services' distribution network. The figure presents the three potential uptake for solar PV, including the January 2018 forecast, a moderate uptake of the Governments' policy (mod) and full uptake of the Governments' policy (full). In planning augmentations to its network, AusNet Services has applied the Solar Mod Policy as the most likely scenario.

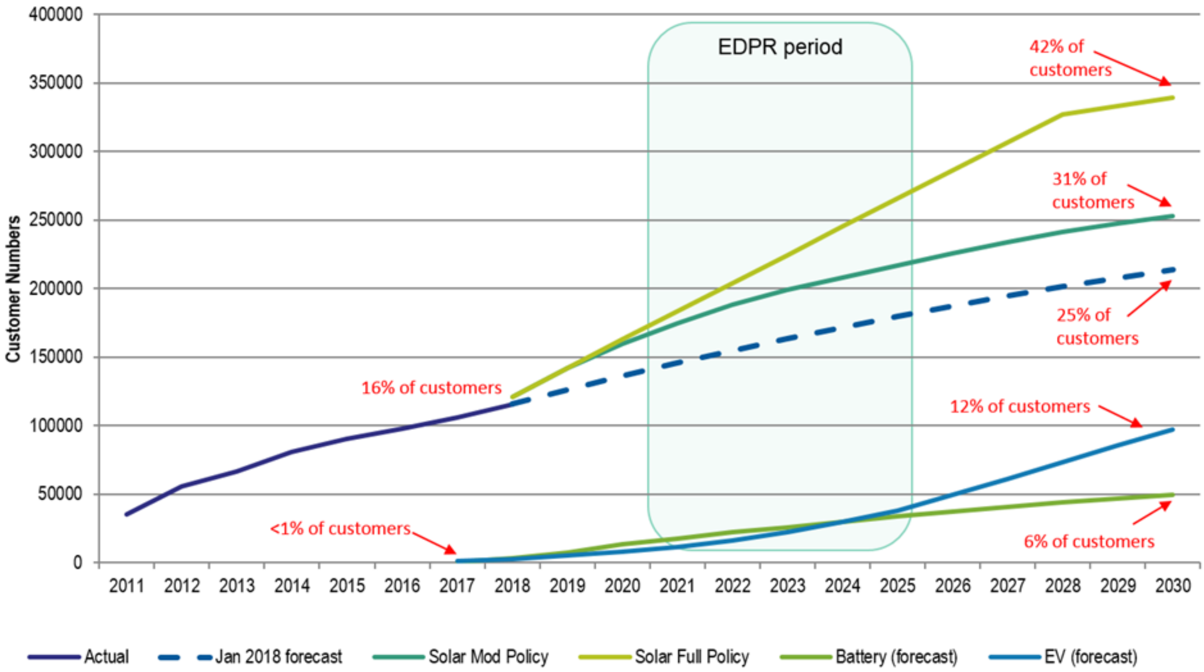

Figure 2: Forecast uptake of DER within the AusNet Services' network

5.4 Zone Substation and Feeder Power Quality Meters

Power quality meters are installed at each zone substation and at the extremity of one distribution feeder emanating from each zone substation in order to monitor and record steady state voltage and voltage variations as required by Clause 4.2.6 of the Electricity Distribution Code.

Currently a combination of [C.I.C]power quality meters are deployed for this purpose in the network.

The meter data from the [C.I.C] is collected by the EziView application, whist [C.I.C] data is collected by the Power Monitoring Expert (PME) application. The meter data from these two applications is stored on two separate IT servers.

Data stored in the EziView application is not readily accessible by engineering staff and requires an application to the IT Services department to release required data.

PME application was commissioned in 2018 to improve PQ compliance requirements and provide engineering staff access to the meter data. However, [C.I.C] are not compatible with the PME application.

There are currently 21 [C.I.C]installed at zone substations and 55 at feeder extremities.

6 Network Performance

6.1 Peak Demand Forecasts

Peak demand forecasts are critical in determining capital expenditure requirements to meet demand-related growth. AusNet Services' internal forecast for peak demand growth has been developed at zone substation and 22kV feeder level using a bottom-up approach enabled by advanced metering infrastructure (AMI) data and network analytics.

Forecast demand indicates relatively low levels of demand growth compared to the past decade, with peak demand forecast to grow at a network-wide average annual rate of 1.3% between summer 2019/20 and summer 2025/26.

The demand forecast includes a geographic variation of peak demand growth across the network. Relatively strong peak demand growth is forecast in the growth corridors at Clyde North (4.5% p.a), Officer (3.1% p.a) and Pakenham (2.2% p.a) in the south east growth corridor and Doreen (2.6% p.a), Epping (2.5% p.a), Kalkallo (2.1% p.a) and Kilmore South (3.7% p.a) in Melbourne's northern growth corridor. Forecast demand growth in these areas is driven predominately by new housing estates, resulting in new customer connections, and demand from community services such employment precincts and public transport.

Embedded generation at customer level, such as solar photovoltaic cells, and energy efficient measures are increasing in prevalence. AusNet Services' maximum demand forecasts inherently include the existing level of customer side demand changes driven by distributed energy resources and energy efficiency. Although not explicitly included in the maximum demand forecasts, the forecast level of solar PV uptake has been separately forecast and assessed as not having a significant impact on maximum demand because solar generation has typically reduced to a minimum before the early evening peak demand period occurs. The impact of customer level distributed energy resources will increasingly have a downward impact on maximum demand as battery technology improves, costs reduce, and more customers invest in them. AusNet Services is continually refining its demand forecasting methodology to include the effects of distributed energy resources and other emerging factors that influence demand.

Most zone substations outside the growth corridors are forecast to experience low demand growth (less than 1.0% p.a) or a decline in demand.

Work has commenced to forecast the maximum demand on distribution substation but is not currently done at the LV network level. At these levels a more general growth rate is applied at the network level to establish the proposed augmentation plan.

6.2 Network Utilisation

6.2.1 Sub-transmission Network

With exception of the MBTS-CLPS-CF 66kV line, loading of AusNet Services' 66kV sub-transmission network is forecast to remain within network limits under system normal conditions. High loading will however occur when an unplanned outage of a network element occurs or assumed generation is not available at the time of peak demand.

Figure 3 illustrates the actual (2018) and forecast (2020 and 2023) utilisation levels for the 66kV sub-transmission loops. Utilisation is based on the 66kV loops' installed capacity and maximum demand under 50% POE conditions.

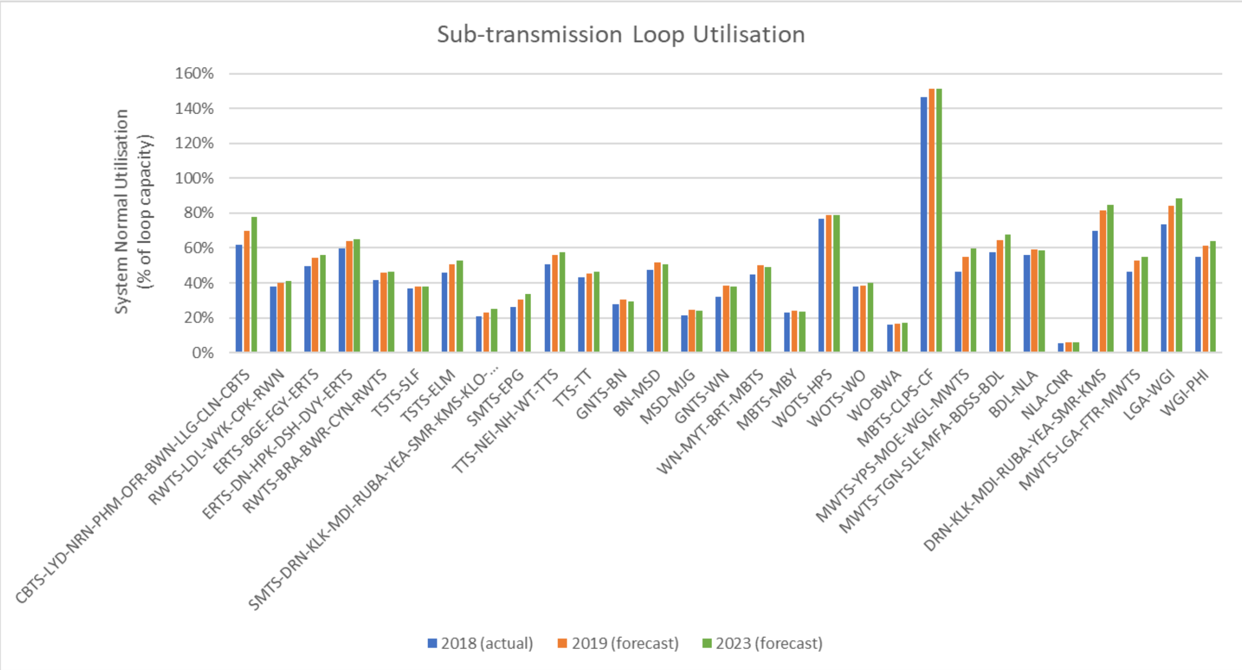

Figure 3: Utilisation levels sub-transmission lines

Utilisation levels of the 66 kV sub-transmission lines are mostly within the range of 30% to 60%, with a few exceptions either side of that range.

The graph shows that the sub-transmission line utilisation levels are forecast to remain reasonably constant over the forecast period, due to low demand growth relative to the loops' installed capacity.

6.2.2 Zone Substations

Figure 4 shows the forecast utilisation of zone substations under outage conditions by comparing the actual (2018) and forecast (2020 and 2023) demand to the zone substation's firm capacity. The firm capacity of the zone substation is the sum the zone substation's transformer cyclic ratings with the largest transformer out of service. For zone substations supplied by a single transformer the transformer's nameplate capacity has been applied.

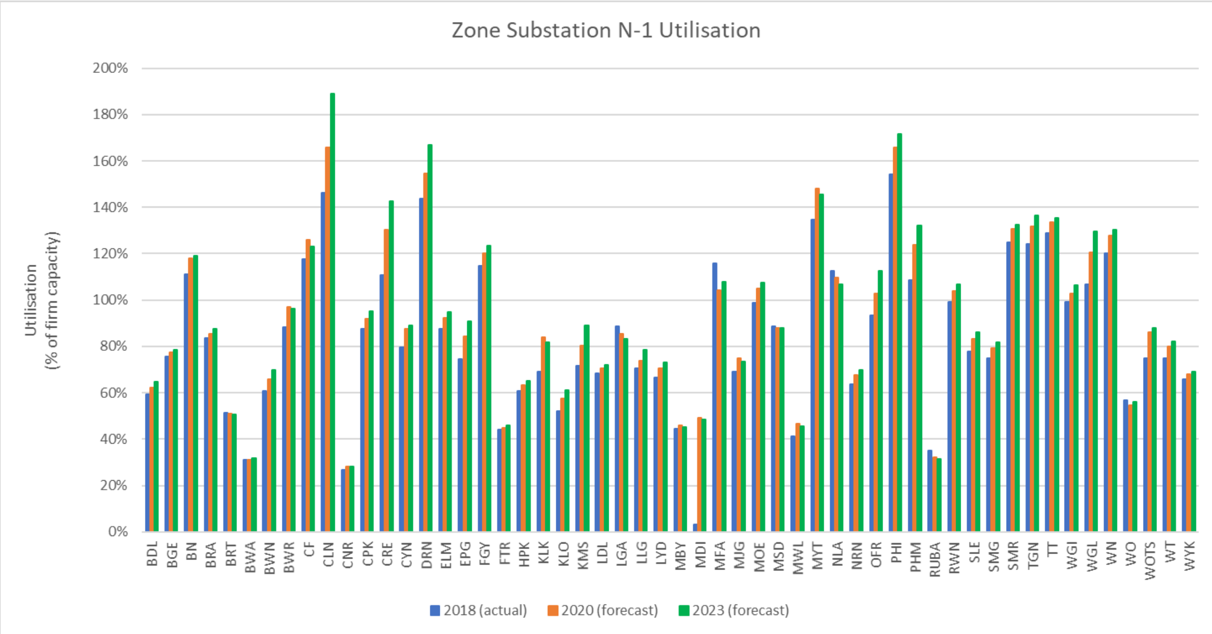

Figure 4: Zone Substation N-1 Utilisation

Under an outage condition for a zone substation transformer there may be some load lost if it occurs at a time when loading exceeds the firm rating. Probabilistic planning considers the energy at risk and outage probability, and monetises this expected unserved energy by multiplying it by the Value of Customer Reliability (VCR).

Excluding the zone substations supplied from a single transformer, there are 20 zone substations that have an N-1 capacity lower than the forecast maximum demand. However, due to the low probability of a transformer outage, the only zone substation transformer capacity augmentation that is economically justified in the 2022-2026 EDPR period is Clyde North (CLN) Zone Substation.

6.2.3 Distribution Feeders

The distribution feeders that are presently overloaded, are forecast to become overloaded or are connected to feeder that is forecast to be overloaded in the next five years are presented in Table 3. The light shaded cells highlight where the demand is forecast to exceed the normal rating, and the dark shaded cells highlight where demand is forecast to be greater than 110% of the feeder rating (the list managed rating), to which suitable feeders can be risk managed with some asset life reduction but inconsequential additional short-term risk.

Table 3: Distribution Feeder Forecasts

Feeder	Rating (A)	110% of Rating (A)	Forecast Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CRE31	375	412.5	P50 (A)	307	325	343	364	382	397	412	427	444	461
			P10 (A)	335	355	375	397	416	433	449	466	483	502
DRN11	326	358.6	P50 (A)	282	294	304	314	323	333	342	352	361	370
			P10 (A)	304	317	328	338	348	359	369	379	389	398
DRN12	341	375.1	P50 (A)	283	299	313	325	337	348	360	371	383	393
			P10 (A)	293	310	325	338	350	363	375	388	400	411
DRN21	315	346.5	P50 (A)	296	301	307	313	324	336	348	361	373	385

Feeder	Rating (A)	110% of Rating (A)	Forecast Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
			P10 (A)	315	321	327	334	345	358	371	383	396	409
OFR22	360	396	P50 (A)	196	208	219	230	241	252	263	274	285	295
			P10 (A)	210	223	235	247	258	270	281	293	304	315
OFR23E	340	374	P50 (A)	281	291	301	310	320	329	338	348	357	365
			P10 (A)	300	310	321	331	341	351	361	371	381	390
OFR24	360	396	P50 (A)	278	282	287	292	296	301	306	310	315	319
			P10 (A)	290	295	299	304	309	314	318	323	328	332
PHM32	345	379.5	P50 (A)	304	318	331	345	359	374	387	399	412	423
			P10 (A)	327	341	356	371	386	402	416	429	443	455
PHM33E	320	352	P50 (A)	270	280	289	299	309	320	331	340	349	357
			P10 (A)	284	294	304	315	326	337	349	359	369	378
KLO14	260	286	P50 (A)	232	236	241	248	252	255	261	267	271	274
			P10 (A)	249	253	259	266	270	274	280	286	290	294
MOE13	205	225.5	P50 (A)	191	193	194	194	195	195	196	197	199	201
			P10 (A)	201	204	204	205	205	206	206	207	209	212

AMS 20-16 Distribution Network Planning Standards and Guidelines describes the methodology adopted in justifying distribution feeder augmentation projects using a probabilistic approach.

6.2.4 Distribution Substations and LV Network

The loading on distribution substation should not exceed 150% of transformer nameplate rating and augmentation should be implemented before this load level is reached. The expected overloading of distribution transformers during the 2022-26 period was analysed utilising AMI data. A forecast was developed using an average load growth for the population of distribution transformers, because AusNet Services has not yet developed demand forecasts for individual distribution transformers. Details of the average load growth forecasting methodology used is given in Appendix B.

The results of this analysis are presented in Table 4. This indicates an increasing trend in the number of transformers expected to become overloaded.

Table 4: Estimated number of overloaded distribution transformers by 2025

PUF	2021	2022	2023	2024	2025
>=140 PUF	162	188	218	237	242
>=150 PUF	112	137	153	179	209

6.3 Customer Voltage Compliance

AusNet Services has developed a tool, known as Explore, that uses AMI data and network analytics to monitor the level of voltage compliance within AusNet Services' distribution network. Explore provides an up-to-date view of the level of voltage compliance and allows 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 target range, 216-253 Volts on the low voltage network. Figure 5 shows how the level of voltage compliance improved between December 2014 and October 2019, with overvoltage (high breach) non-compliance reducing from approximately 30% to 10%. It also shows that compliance with the undervoltage (low breach) limits has been mostly maintained. The straight line between late-2015 and late-2016 is due to data that is still to be back-populated in the Explore analytics tool.

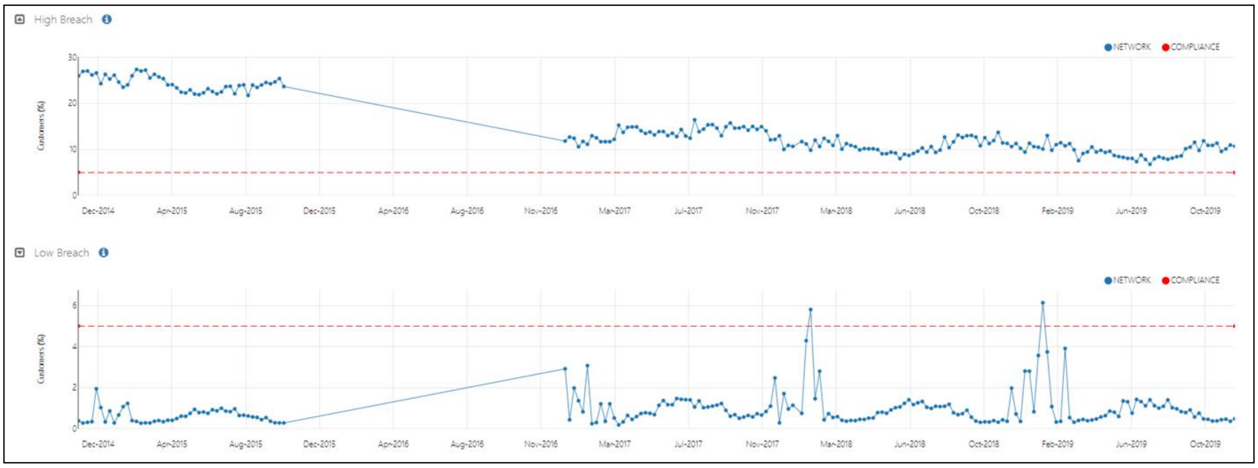

Figure 5: Improvement in voltage compliance

The improvement in voltage compliance seen in Figure 5 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 solar PV.

6.4 Network Capacitive Current Forecast

To ensure the ongoing compliance of the REFCLs (refer Section 4.3), a forecast of network capacitive current was developed. The forecasts were prepared following a capacitive current forecasting methodology developed by AusNet Services with input from The Centre for International Economics (The CIE).

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

1. Network growth;
2. Replacement programs; and
3. Network augmentation.

Network growth considers the impact of new underground residential developments and the new cables and substations required to supply these newly developed areas. In line with the demand forecasting methodology, this network growth forecast uses AusNet Services' customer growth forecast, which is informed by government growth estimates.

In developing the network growth forecasting methodology, a back-casting assessment of network growth compared to customer number growth, between 2015 and 2019, was undertaken. From this assessment, a direct link to the customer number growth forecast was established, with a network growth rate of:

- 12 meters of new underground cable per customer for rural areas; and
- 8 meters of new underground cable per customer for urban areas.

Replacement programs include programs where existing overhead conductors are replaced by covered conductor or underground cable, usually driven by bushfire mitigation programs.

Network augmentation accounts for the replacement of pole top transformers with larger units to meet increases in demand and the construction of any new distribution feeders or zone substations.

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 GFN 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 1 November 2019)

ZSS	Region	Number of Feeders	Number of GFNs	ASC Limit	2019 Capacitive Current	2025 Capacitive Current
BDL	East	8	2	100	234	248
BGE	Central	6	2	100	219	220
BN	Central	5	1	100	81	83
BWA	North	4	1	129	72	73
ELM	Central	8	2	100	223	252
FGY	Central	10	2	100	150	156
KLK	Central	3	1	85	72	130
KLO	Central	7	2	100	321	367
KMS	North	2	1	80	70	105
LDL	Central	8	2	100	193	210
LLG	Central	3	1	100	68	83
MSD	North	8	2	100	60	69
MOE	East	8	2	100	134	138
MYT	North	4	1	122	59	60
RUBA	North	3	1	130	79	81
RWN	Central	7	1	100	109	117
SLE	Central	4	1	100	67	75
SMR	North	6	2	134	160	178
WGI	East	8	1	148	144	158

Augmentation

ZSS	Region	Number of Feeders	Number of GFNs	ASC Limit	2019 Capacitive Current	2025 Capacitive Current
WN	North	7	2	152	193	199
WOTS	North	6	2	100	223	235
WYK	Central	4	2	130	248	251

7 Proposed Work

7.1 Zone Substations

7.1.1 Clyde North Zone Substation Third Transformer

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 30,000 residential, commercial, industrial and agricultural customers in Victoria's southeast growth corridor.

The supply area is surrounded by Cranbourne (CRE) and Hampton Park (HPK) Zone Substations in the west, Berwick North (BWN) Zone Substation in the north and Officer (OFR) Zone Substation in east.

CLN Zone Substation is a summer peaking substation with a forecast maximum demand growth rate averaging 4.4% per annum over the next 10-year period. The growth in demand is predominately driven by the significant expansion of residential and commercial development in Melbourne's southeast growth corridor.

The zone substation summer maximum demand recorded in 2017/18 was 63.6 MVA. The forecast summer maximum demand is given in Table 6.

Table 6: Forecast Summer Maximum Demand

Probability of Exceedance (POE)	Forecast Summer Maximum Demand 2018/19 (MVA)	Forecast Summer Maximum Demand 2024/25 (MVA)
50%	68.8	89.7
10%	73.3	95.8

The zone substation capacity, consisting of a nameplate rating of 66 MVA, and 'N' and 'N-1' cyclic ratings of 87.3 MVA and 43.5 MVA respectively, is insufficient to reliably supply the forecast maximum demand, meaning that the current level of supply to our customers is expected to diminish if some service level risk mitigation action is not undertaken.

In addition to the zone substation constraints, supply capacity is also limited at the feeder circuit level, where electricity demand growth is forecast to exceed the capacity of multiple feeder circuits, similarly resulting in a service level reduction unless some risk mitigation action is taken.

The options analysis identifies that the proposed preferred option, being the one that maximises the net economic benefit to all those that produce, consume and transport electricity in the NEM, is to install a third 20/33 MVA transformer and third 22 kV switchboard at Clyde North (CLN) zone substation by November 2024, at a project cost of [C.I.C] (Real, $2018).

Further details of this project can be found in AMS 20-316 *Planning Report – Clyde North (CLN) Zone Substation Service Level Constraints*.

7.2 Distribution Feeders

7.2.1 CRE31 Feeder

CRE31 is situated in the south eastern growth corridor and the load is growing at the rate of 5% per annum.

The growth is mainly due to the population/housing growth in the area.

The feeder was reconfigured with CRE32 and CRE22 in 2018 to avoid the over-loading during summer 2018/19. The feeder will be over-loaded again in summer 2021/22 and thus need address the issue again.

The following options were considered to address this issue:

1. Demand management – this option will be considered. This option alone may not be sufficient to address the over-loading issue.
2. Risk manage the feeder – Feeder will be risk managed during summer 2021/22. Beyond 2022 it is not possible to risk manage as the 10%POE forecast is greater than 110% of the feeder rating.
3. Feeder reconfiguration – As feeder reconfigurations were carried out in 2018, no further reconfigurations are possible.
4. Uprate the feeder – Unable to uprate the feeder above 375A.
5. Battery Banks and/or generators will be considered during RIT-D stage if required.
6. New feeder – New CRE24 feeder to off-load CRE31 will be required for the summer of 2021/22 to avoid over-loading of CRE31 feeder. The feeder will be risk managed for the summer of 2021/22 with the new feeder required by November 2022.

Option 6 (New Feeder) is the preferred option. The Options 1 to 4 will not be adequate to address the loading issue on CRE31. The option 5 will need to be investigated further with other interested parties.

Thus, at this stage new CRE24 feeder will be the preferred option and it is required by November 2022.

The capital cost of this option is [C.I.C].

One or two industrial/commercial customers have inquired about large loads in this area to be connected to this feeder. These loads are not confirmed yet and it is in the order of 4MW. Thus, the new feeder option will address these industrial/commercial and residential growth in the area.

7.2.2 DRN11, DRN21 and DRN12 Feeders

DRN12 feeder is situated in the northern growth corridor and the load is growing at the rate of 4% to 5% per annum.

The growth is mainly due to the population/housing growth in the area.

DRN12 was reconfigured in 2017 with DRN11 and DRN21 to mitigate the over-load. It was reconfigured again with DRN11 in 2018 to avoid the over-loading during summer 2018/19.

DRN21 will be over-loaded in summer 2020/21 and thus need address the issue again.

The options considered are:

1. Demand management – this option will be considered. This has been used in the past and we have 2MW load reduction available on DRN12, if needed. This customer needs to be contracted for future years.

2. Risk manage the feeders:
    a. DRN11 feeder can be risk managed during summer 2022/23. Beyond 2023, it is not possible to risk manage as the 10%POE forecast is greater than 110% of the feeder rating.
    b. DRN12 feeder can be risk managed from summer 2022/23 to summer 2024/25. Beyond 2025, it is not possible to risk manage as the 10%POE forecast is greater than 110% of the feeder rating.
    c. DRN21 feeder will be risk managed from summer 2020/21 to summer 2022/23. Beyond 2023, it is not possible to risk manage as the 10%POE forecast is greater than 110% of the feeder rating.
3. Feeder reconfiguration has been carried out twice since 2017. No further reconfigurations are possible.
4. Feeder upgrade/uprate is not possible.
5. Battery Banks and/or generators will be considered during RIT-D stage if required.
6. New DRN24 feeder to off-load DRN11/DRN12/DRN21 will be required by November 2023 to avoid over-loading of DRN21, DRN11 and DRN12 feeders.

Option 6 (New Feeder) is the preferred option. The Options 1 to 4 will not be adequate to address the loading issue on DRN21, DRN11 and DRN12. The option 5 will need to be investigated further with other interested parties.

Thus, at this stage new DRN24 feeder will be the preferred option and it is required by November 2023.

The capital cost of this option is [C.I.C].

7.2.3 PHM32, OFR22, OFR23E and OFR24 Feeders

OFR22, OFR23E and OFR24 feeders are situated in the south eastern growth corridor and the load is growing at the rate of 3% to 4% per annum.

The growth is mainly due to the population/housing growth in the area. Metro Trains is connecting a new 1.7MW substation to OFR22 feeder to supply their new trains in 2019.

One or two industrial/commercial customers have inquired about large loads in this area to be connected to OFR24 feeder. These loads are not confirmed yet and it is in the order of 4-6MW. The forecast given above do not include these new industrial loads as they are not confirmed.

PHM32 feeder will be over-loaded in summer 2020/21 and need to address the over-load issue.

The options considered are:

1. Demand management – this option will be considered. This option alone may not be sufficient to address the over-loading issue.
2. Risk manage the feeders:
    a. OFR23E feeder will be risk managed from summer 2024/25 to summer 2025/26. Beyond 2025, it is not possible to risk manage as the 10%POE forecast is greater than 110% of the feeder rating.
    b. PHM32 feeder can be risk managed during summer 2021/22. Beyond 2022, it is not possible to risk manage as the 10%POE forecast is greater than 110% of the feeder rating.
3. OFR21 and OFR22 Feeder reconfiguration has been carried out in 2018. No further reconfigurations are possible.

4. Unable to upgrade feeders.
5. Battery Banks and/or generators will be considered during RIT-D stage if required.
6. New OFR second switch board and OFR11 feeder to off-load PHM32, OFR22, OFR23E and OFR24 will be required by November 2022 to avoid over-loading of OFR23E and OFR22 feeders.

Option 6 (New Feeder) is the preferred option. The Options 1 to 4 will not be adequate to address the loading issue on OFR23E and PHM32. The option 5 will need to be investigated further with other interested parties.

Thus, at this stage new second switchboard and new OFR11 feeder will be the preferred option and it is required by November 2022.

The capital cost of this option is [C.I.C].

7.2.4 PHM33 Feeder

PHM33 feeder is situated in the South Eastern growth corridor and the load is growing at the rate of 3% to 4% per annum.

The growth is mainly due to the population/housing growth in the area.

Metro Trains is connecting a new 7MW substation in 2019 to supply their new trains to this feeder. Metro Trains use this as their standby feeder whereas new PHM23N feeder will be constructed in 2018 as dedicated feeder to supply the Metro train.

PHM33 will be converted to piggyback feeder in 2018 to provide the standby supply to Metro train. This will be named as PHM33S and the existing PHM33 feeder will be named as PHM33N.

The PHM33N will be over-loaded in summer 2022/23.

The options considered are:

1. Demand management – this option will be considered. This option alone may not be sufficient to address the over-loading issue.
2. Risk manage the feeder – Feeder will be risk managed from summer 2023/24 to summer 2024/25. Beyond 2025, it is not possible to risk manage as the 10%POE forecast is greater than 110% of the feeder rating.
3. Feeder reconfigurations are not possible.
4. Feeder upgrade is not possible.
5. Battery Banks and/or generators will be considered during RIT-D stage if required.
6. New piggy-back feeder PHM23S feeder to off-load PHM33N will be required by November 2025 to avoid over-loading of PHM33N feeder.

Option 6 (New Feeder) is the preferred option. The Options 1 to 4 will not be adequate to address the loading issue on PHM33. The option 5 will need to be investigated further with other interested parties.

Thus, at this stage PHM23S feeder will be the preferred option and it is required by November 2025.

The capital cost of this option is [C.I.C].

7.2.5 KLO14 Feeder

KLO14 feeder is situated in the northern growth corridor and the load is growing at the rate of 2% per annum.

The growth is mainly due to the population/housing growth in the area.

The feeder will be over-loaded by summer 2023/24.

The options considered are:

1. Demand management – this option will be considered. This option alone may not be sufficient to address the over-loading issue.
2. Risk manage the feeder – Feeder will be risk managed from summer 2023/24 to summer 2024/25 and beyond 2025 it is not possible to risk manage as the 10%POE forecast is greater than 110% of the feeder rating.
3. Feeder reconfigurations are not possible.
4. Feeder upgrade is the most economical solution to address the over-loading issue.

Option 4 Feeder Upgrade is the preferred option. The options 1 to 3 will not be adequate to address the loading issue on KLO14.

Thus, at this stage KLO14 feeder upgrade from 260A to 360A will be the preferred option and it is required by November 2025.

The capital cost of this option is [C.I.C].

7.2.6 MOE13

MOE13 supplies part of Moe and the Newborough area in West Gippsland. This feeder has sections of conductor that are in poor condition and the feeder is forecast to reach its thermal rating of 205A in 2022. In addition to the feeder being heavily loaded, the surrounding 22kV feeders are also heavily loaded and unable to provide load transfer capacity during an outage.

The risk mitigation options considered include:

1. Demand management.
2. Risk manage the feeder – feeder loading up to 110% of the feeder's normal rating is allowed short periods of the summer peak demand. However, loading feeders above 100% of their normal rating is expected to result in a small reduction in conductor's expected life.
3. Feeder reconfigurations – feeder
4. Feeder upgrade – upgrade the feeder's capacity by reconducting approximately 900m of 3-7/.104Cu conductor with 19/3.25AAC

Due the condition of some conductor sections, it is not appropriate to risk manage this feeder above 100% of its normal rating. The proposed preferred solution is to upgrade feeder MOE13 by reconductoring approximately 900m of the circuit. This is a relatively low-cost option that provides a capacity increase sufficient to meet the forecast demand growth and provide much needed transfer capacity to the adjacent heavily loaded network. This option will increase the feeder rating from 205A to 230A and replace the poor condition section of the conductor. The optimal timing of this solution is by November 2023.

The capital cost of this option is estimated at [C.I.C].

7.3 Summer Readiness Program

The aim of the summer readiness program is to prepare the HV network for the expected peak demand during the upcoming summer period. This is a proactive program undertaken each year before the start of the summer season and runs from April to November. The process is documented in SOP 30-31 *Summer Preparation Process (Electricity Distribution Network)*.

As part of the summer preparedness a range of activities are carried out including plant serviceability checks, protection settings review, and completion of critical maintenance activities, thermo-vision of highly loaded lines and zone substations, and establishment of arrangements for acquisition of emergency generation.

Network Support contracts are also procured from commercial and industrial customers who can voluntarily curtail load when required.

Expenditure for this program has been forecast in line with historical expenditure (Table 7).

Table 7: Historic and Forecast Expenditure for Summer Readiness Program

Program	2016	2017	2018	2019	2020	2022-2026
Summer Readiness	C.I.C					

Notes:

1. 2016-2018 sourced from annual regulatory accounts
2. 2019 sourced from Electricity Networks FY19 to FY23 Works Program FY19 Edition
3. 2020 sourced from Electricity Networks FY20 to FY24 Works Program FY20 Edition

7.4 Eliminating Network Operational Deficiencies

The aim of this program is to rectify operational deficiencies identified in the medium voltage and low voltage circuits. These deficiencies are identified by regional technical staff, line workers and CEOT/operators in the course of operating and maintaining the network.

These deficiencies typically fall within the following categories:

1. Ferro-resonance caused by single-phase switching of resonant multiphase cable and transformer combinations which will cause supply outages and damage plant.
2. Inadequate medium voltage fuse ratings or coordination with other protection devices causing unnecessarily large supply outages for minor network faults.
3. Fault level increases or un-fused lines where the conductor, equipment or plant rating is less than the network fault level and a fault may result in equipment failure.

This is a reactive program based on the needs of operational staff in order to maintain safety and reliability of the network.

This program typically consists of the installation or relocation of switches and system reconfiguration to improve system operability.

Expenditure for this program has been forecast in line with historical expenditure (Table 8).

Table 8: Historical and Forecast Expenditure for Eliminating Network Operational Deficiencies

Program	2016	2017	2018	2019	2020	2022-2026
Eliminating Network Operational Deficiencies	C.I.C					

Notes:

1. 2016-2018 sourced from annual regulatory accounts
2. 2019 sourced from Electricity Networks FY19 to FY23 Works Program FY19 Edition
3. 2020 sourced from Electricity Networks FY20 to FY24 Works Program FY20 Edition

7.5 Power Quality Monitoring (Meter Installations)

As discussed in Section 5.4, there are a number of issues with power quality meters in zone substation and at feeder extremities.

AusNet Services proposes to replace all power quality meters not currently compatible with its Power Monitoring Expert (PME) software.

The program consisting of:

- Replacing EDMI power quality meters with [C.I.C] meters at 21 zone substations;
- Replacing EDMI power quality meters with [C.I.C] meters at 55 distribution feeder extremities; and
- Integrate the meter data from these new meters into PME.

AusNet Services intends to consolidate power quality data from these meters into one information technology (IT) platform; thereby enabling continuous monitoring and reporting based on exceptions.

This project has been delayed due to the reprioritisation of resources to a number of major IT projects that the business has undertaken in recent years, including the AMI project.

The forecast expenditure for this program is [C.I.C] in 2021/2022.

The breakdown of this expenditure is given in Appendix A.

7.6 LV Network Capacity Program

The aim of this program is to manage the performance of the LV network and respond to changes in customer load and generation profiles over time.

This is a proactive program focusing on minimising outages caused by transformer failure and LV fuse operations due to overloads and voltage regulation issues caused by changes to the LV network, such as changes to customer load and local generation.

The typical work undertaken under this program includes:

- Upgrading distribution transformers
- Rearranging the network to distribute customers more evenly
- Reducing circuit overloading by upgrading or splitting circuits
- Splitting LV networks by installing new distribution substations

This work is only carried out after extensive field investigations to validate desk top analysis using AMI data.

As discussed in Section 6.2.4, AusNet Services is forecasting an increase in the number of transformers expected to become overloaded in the 2022-2026 regulatory period.

Assuming a replacement cost of [C.I.C] per transformer, expenditure of [C.I.C] is forecast for this program.

Expenditure for this program has been forecast in line with historical expenditure (Table 9).

Table 9: Historical and forecast expenditure for LV Network Capacity

Program	2016	2017	2018	2019	2020	2022-2026
LV Network Capacity	C.I.C					

Notes:

1. 2016-2018 sourced from annual regulatory accounts
2. 2019 sourced from Electricity Networks FY19 to FY23 Works Program FY19 Edition
3. 2020 sourced from Electricity Networks FY20 to FY24 Works Program FY20 Edition

7.7 Voltage Compliance Programs

The program of work for the period through to the end of 2025 will include the following components:

- Customer Supply Compliance Program
- Steady State Voltage Compliance
- Technology Program – Integration of Distributed Energy Resources

7.7.1 Customer Supply Compliance Program

This is a reactive program that addresses quality of supply issues identified by customers within AusNet Services' 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

Note: In some instances, customer's voltage complaints can be resolved by adjusting transformer taps or phase balancing that will not incur capital expenditure under this program. Those costs will be allocated to the relevant operational cost code.

Expenditure for this program has been forecast in line with historical expenditure (Table 10).

Table 10: Historical and forecast expenditure for Customer Compliance Program

Program	2016	2017	2018	2019	2020	2022-2026
Customer Compliance	C.I.C					

Notes:

1. 2016-2018 sourced from annual regulatory accounts
2. 2019 and 2020 sourced from FY20-24 Financial Plan Data.

The spend profile for this program has been forecast assuming an increase in expenditure over the first two years of the next period, in line with historic expenditure trends, and then a decline in expenditure due to the impact of the Steady State Voltage Compliance Program (Section 7.7.2), which is proactive program to better enable integration of solar PV generation. The total cost of the program over 2022-26 period is [C.I.C] (real $2018). In the absence of the Steady State Voltage Compliance Program, expenditure in this reactive program would be forecast to increase over the entire period rather than decline.

7.7.2 Steady State Voltage Compliance Program

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

AusNet Services has developed an economic approach to valuing the impact of overvoltage on solar generation. This approach uses outputs from AusNet Services' Substation Health 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, which is constrained due to voltage non-compliance issues and compares this to the cost of augmentation options.

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 Services' geo-spatial system, SDMe, to determine where in the network the constrained substations are positioned and the critical equipment likely to be causing the voltage non-compliance, 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 within the 2022-2026 year period with the largest net benefit is then included in EDPR submission as the most economical solution

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).

Four program options were considered, with 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.

The key parameters of the four program options are tabulated below.

<table>
<tr><th></th><th>Option 1:
Do nothing</th><th>Option 2: Address existing voltage issues</th><th>Option 3: Address existing and future voltage issues</th><th>Option 4: Aiming for zero constraints</th></tr>
<tr><td>Cost ($ million)</td><td>-</td><td colspan="3" rowspan="3">C.I.C</td></tr>
<tr><td>Cost per customer ($)</td><td>-</td></tr>
<tr><td>NPV Benefit ($ million)</td><td>-</td></tr>
<tr><td>Number of customers voltage performance improved by 2025</td><td>-</td><td>53,000</td><td>228,000</td><td>235,000</td></tr>
<tr><td>Number of solar customers voltage performance improved by 2025</td><td>-</td><td>16,000</td><td>93,000</td><td>95,000</td></tr>
<tr><td>Number of customers without any voltage improvements by 2025</td><td>235,000</td><td>182,000</td><td>7,000</td><td>Aiming for 0</td></tr>
<tr><td>Percentage of 2025 customer base without any voltage improvements</td><td>29%</td><td>22%</td><td>1%</td><td>Aiming for 0%</td></tr>
<tr><td>Total export enabled of previously unserved generation over 2022-26 (GWh)</td><td>0</td><td>183</td><td>969</td><td>1380</td></tr>
<tr><td>% Export enabled of previously unserved generation over 2022-26</td><td>0%</td><td>13%</td><td>70%</td><td>Aiming for 100%</td></tr>
</table>

AusNet Services’ proposed preferred solution is Option 3, at a cost of [C.I.C] ($2018) over 2022-26, 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 [C.I.C] (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.

Further information and detail on the economic approach applied is available in AMS 20-401 Steady State Voltage Compliance.

7.7.3 Technology Program – Integration of Distributed Energy Resources

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 Services, the power-flow models of the network are currently derived from the geo-spatial system, SDMe, and fed into a power-flow engine, namely [C.I.C]. Only the 22 kV network data is extracted into the [C.I.C] with load data approximated by a manual process involving SCADA measurements and AMI data.

AusNet Services have identified significant limitations in the current modelling process:

- Lack of usable data for the LV section of the network.
- Lack of automation and incorporation of times-series AMI and SCADA data as inputs to the model

A fully functional HV to LV model will enable AusNet Services to better plan, integrate and manage the impact of DER allowing 'what if' scenario analysis.

In the current regulatory period, AusNet Services has carried out a trial on the HPK21 feeder to test the HV to LV modelling concept. AusNet Services plans to extend its learnings from this trial in the next regulatory period.

In addition, the technology program also includes activities on establishment of the foundation required for a future ready forecasting model and DENOP.

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. This includes the extension of HPK21 trial in current regulatory period, using [C.I.C].
- GIS Network Data Quality Improvements – Work to improve the quality of data in the GIS, to overcome current limitations of SDMe. This will feed into the HV to LV Model.
- 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 Control/Optimisation (DENOP) – Work to expand and productionise the DENOP platform under trial in the current period
- P2P trading – Activities to facilitate AusNet Services 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.

The total cost of the program over 2022-26 period is [C.I.C].

Further details of the proposed program are included in the Technology Program – Integration of Distributed Energy Resources.

7.8 Rapid Earth Fault Current Limiters (REFCL)

7.8.1 Capacitive Balance

Policy REF 30-09 *Maintaining Capacitive Balancing* has been written to slow the deterioration of capacitive imbalance in REFCL networks. Under this policy, an individual project is allowed to contribute up to 25 mA of capacitive imbalance. Where a project is expected to contribute more than 25 mA of imbalance, works must be included to bring the imbalance contribution back within the 25 mA threshold. The threshold of 25 mA was selected to acknowledge the fact that in some cases it may be impossible or prohibitively expensive to completely engineer out all imbalance, and in that case it is unfair to require a customer to fund all the remediation the works that would be required.

Consequently, a section may go out of balance after a few projects requiring a network initiated augmentation to bring the section back within an acceptable level of imbalance.

This will be done by using the concepts and tools of policy REF 30-06 including:

- installing new LV capacitive balancing units
- performing phase rotations
- adding the third phase conductor to single-phase spurs

7.8.2 REFCL Compliance Maintained

Even after initial REFCL compliance is achieved, network growth, due to new underground residential developments, and line and cable replacement and augmentation works, will result in network capacitive current changes over time.

As outlined in Section 6.4, AusNet Services has prepared a capacitive current forecast using its newly developed capacitive current forecasting methodology. Comparing the forecasts to the number of GFNs and the ASC limit at each zone substation demonstrates that numerous REFCL zone substations will require augmentation works to maintain compliance throughout the 2022-26 EDPR period.

In identifying the proposed preferred solution to maintain REFCL compliance, AusNet Services has generally taken a least cost technically feasible approach, and most available solutions require at least some level of exemption to the regulations. The options considered in each case generally include:

- Business as usual – no additional investment to maintain REFCL compliance is included beyond achieving initial compliance. Where network capacitive current is forecast to exceed the stations ASC limit, this is not a feasible option as it does not allow AusNet Services to meet its compliance obligations
- Capacitance/Load Transfer – transfer sections of network to an adjacent zone substation.
- Install an additional REFCL – where a station only consists of one REFCL, but multiple transformers, a second REFCL can be installed to increase the capacitive current limit of the station. However, even where a zone substation has three or transformers, existing technology limitations do not allow for installation of a third REFCL at a single zone substation.
- Install isolation transformer(s) – isolate sections of underground network, via isolation transformers, so the zone substation REFCL does not see the network capacitance beyond the isolating transformer(s). This option requires suitably located land to house the isolating transformer(s), and is not suitable where the network beyond the isolating transformer has overhead line sections that cannot be exempt from the regulations.
- Install remote REFCLs – The remote REFCL solution is currently under development by AusNet. It isolates part of a feeder and protects that isolated section with its own REFCL. The plant can be

located no closer than 100m to the zone substation due to earthing issues. This option requires a suitably located large portion of land to house the remote REFCL and associated equipment.

- Underground overhead lines – While undergrounding all overhead network in high bushfire risk areas is not most effective way to mitigate bushfire risk, this option is commonly a very expensive option due to the amount of network required to be undergrounded.
- New Zone Substation – Establish a new zone substation to transfer network away from the constrained zone substation. The new zone substation could REFCL protected and have overhead or underground network transferred, or non-REFCL protected and have only unprotected underground or low bushfire risk overhead line sections transferred to it.

Table 5 shows that ten of the twenty-two REFCL zone substation will exceed their capacitive current limit before or during the 2022-26 EDPR period. The zone substations requiring augmentation, and AusNet Services' proposed preferred solution, to achieve and/or maintain REFCL compliance through to 2026 include:

- BDL - to maintain compliance at BDL it is proposed to establish a new REFCL protected Lakes Entrance (LKE) Zone Substation by 2022 at an estimated cost of [C.I.C]. This option includes feeder transfers from BDL to LKE. Refer to AMS 20-407 for further information.
- BGE - to maintain compliance at BGE it is proposed to reconfigure and augment feeders BGE11 and BGE12, and complete permanently transfers from BGE to Ferntree Gully (FGY) zone substation, at an estimated cost of [C.I.C]. Refer to AMS 20-406 for further information.
- ELM - to achieve and maintain compliance at ELM it is proposed to establish a new REFCL protected Diamond Creek (DCK) Zone Substation by 2025 at an estimated cost of [C.I.C]. This option includes feeder transfers from ELM to DCK. Refer to AMS 20-405 for further information.
- KLK – to maintain compliance at KLK it is proposed to install a remote REFCL to effectively reduce the capacitive current seen at KLK's 22kV bus. Installation of the remote REFCL is proposed prior to 2022, and its expenditure is therefore not considered as part of the 2022-26 EDPR submission.
- KLO - to achieve and maintain compliance at KLO it is proposed to establish a new REFCL protected Kalkallo North (KLN) Zone Substation. This option includes transfer of all overhead feeders away from KLO to KLN such that KLO would only supply underground feeders and be exempt from the regulations. Proposed expenditure to achieve REFCL compliance at KLO will be requested via a Contingent Project Application (CPA), and its expenditure is therefore not considered as part of the 2022-26 EDPR submission.
- KMS - to maintain compliance at KMS it is proposed to replace the existing arc suppression coil (ASC) with a larger capacity ASC by 2023 at an estimated cost of [C.I.C]. Refer to AMS 20-404 for further information.
- LDL - to maintain compliance at LDL it is proposed to install an isolation transformer on feeder LDL21, beyond switch LD727, by 2024 at an estimated cost of [C.I.C]. Refer to AMS 20-403 for further information.
- RWN - to maintain compliance at RWN it is proposed to install a second REFCL at RWN by 2021 at an estimated cost of [C.I.C]. Refer to AMS 20-402 for further information.
- WGI - to maintain compliance at WGI it is proposed to install a second REFCL at WGI by 2021 at an estimated cost of [C.I.C]. This option also includes replacing the No.2 66/22kV transformer with a higher capacity (20/33 MVA) unit to avoid overload during the split bus arrangement. Refer to AMS 20-401 for further information.
- WOTS - to maintain compliance at WOTS it is proposed to establish a new REFCL protected Baranduda Zone Substation by 2021 at an estimated cost of [C.I.C]. This option includes

feeder transfers from WOTS to the new zone substation. Refer to AMS 20-400 for further information.

Further detail on the network limitations and options assessments are available in the individual Asset Management Strategy (AMS) REFCL Compliance Maintained Planning Reports prepared on a per zone substation basis.

Appendix A Power Quality Meter Program Estimate

C.I.C

Appendix B Plant Utilisation Factor (PUF) Calculation Methodology

B.1 Methodology Overview

The first step in calculating a plant utilisation factor (PUF) is the creation of a distribution substation daily load profile using AMI data (15 minutes intervals) as shown in Figure 6.

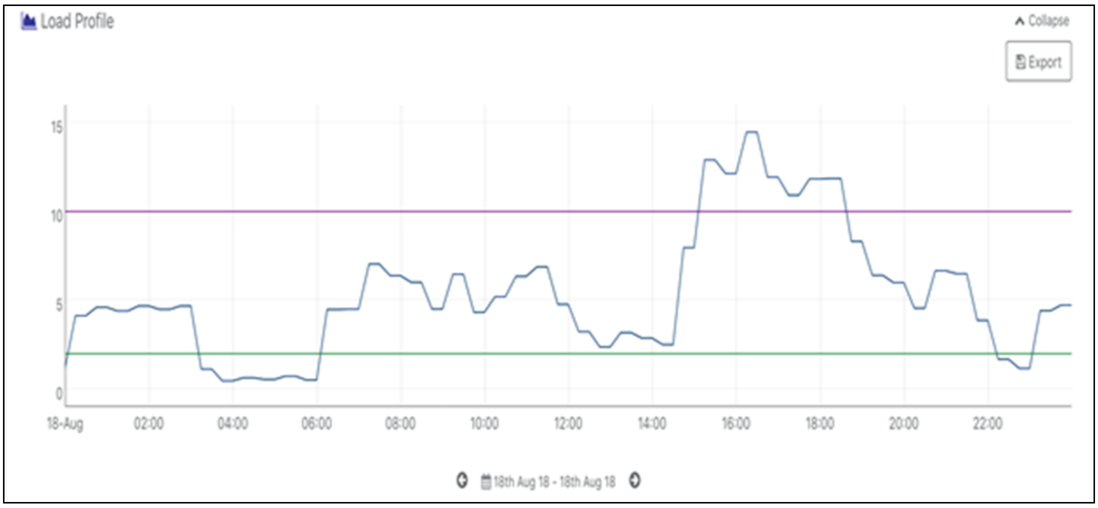

Figure 6: A Distribution Substation Daily Load Profile

A PUF value, based on the nameplate rating of the transformer, is calculated at each 15 minutes interval as shown in Figure 7.

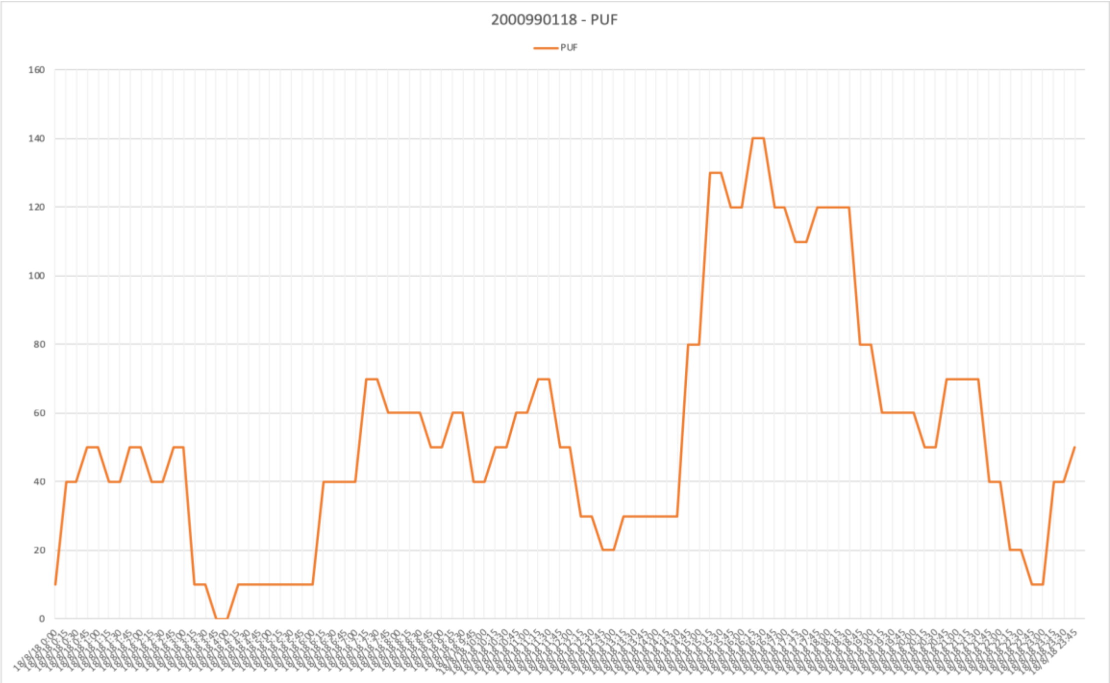

Figure 7: Transformer PUF at 15 minutes Intervals

These PUF values are then sorted from highest to lowest to create a PUF distribution profile, as shown in Figure 8 and Figure 9.

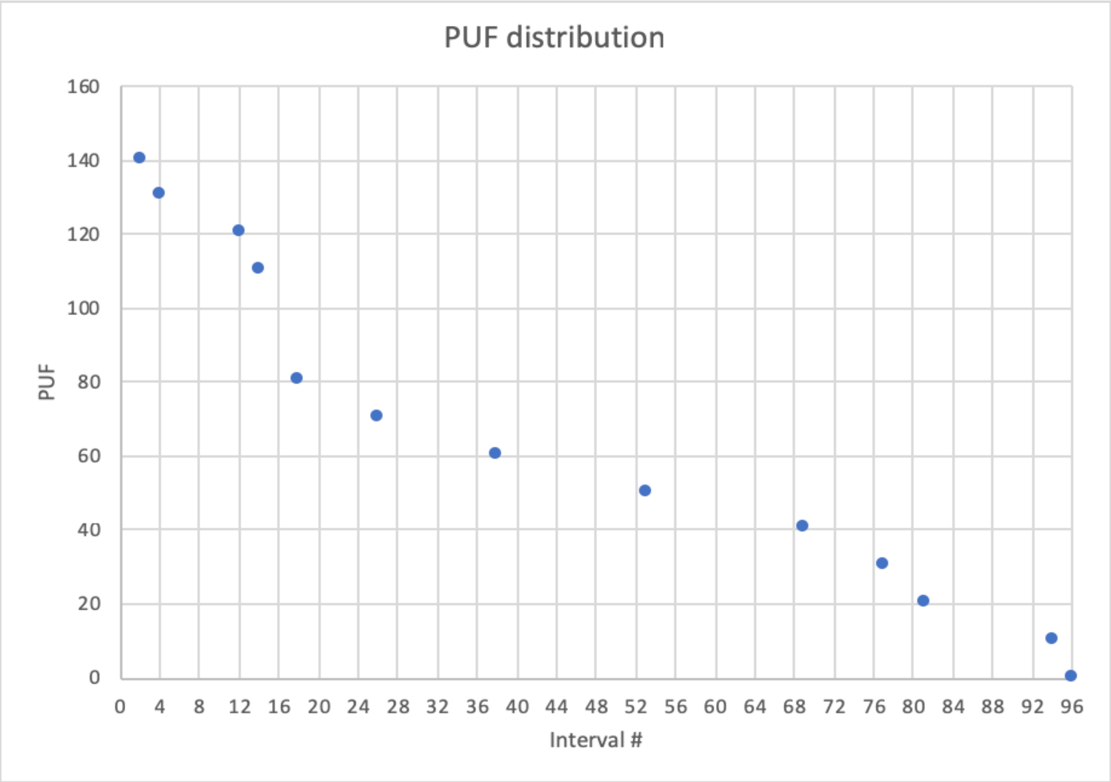

Figure 8: PUF Distribution Profile

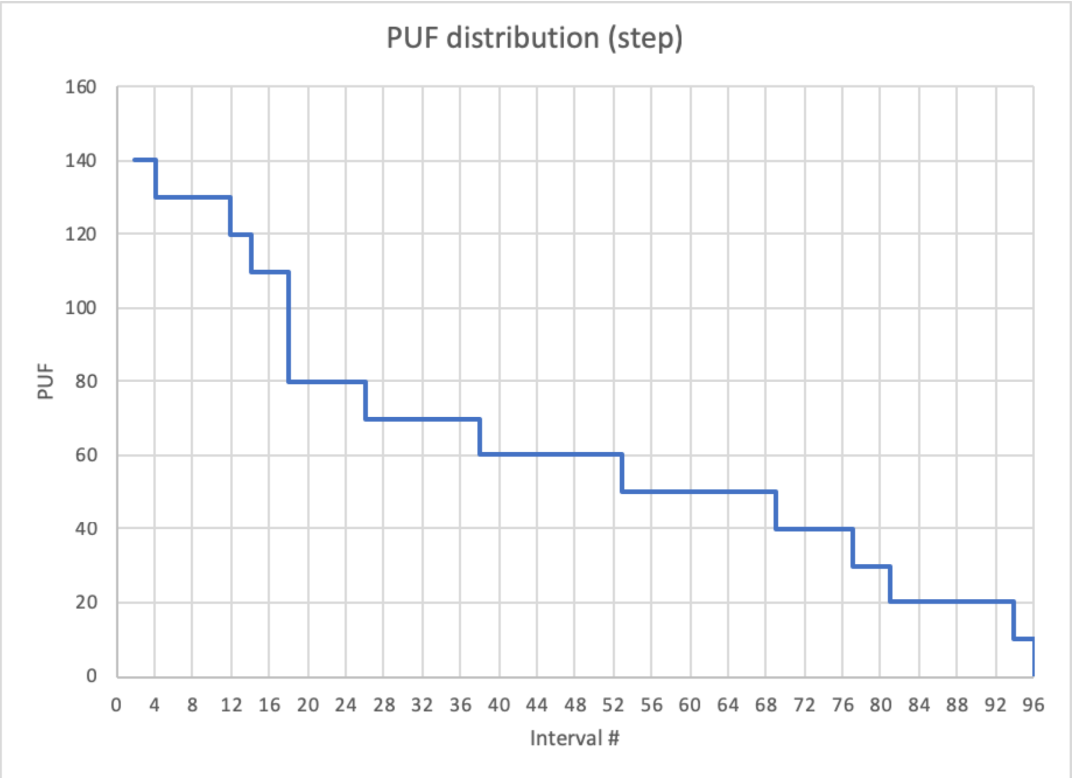

Figure 9: PUF Distribution – Step Profile

Different thresholds can be used on the PUF distribution step-profile to identify emerging issues with substation loading, as shown in Figure 10.

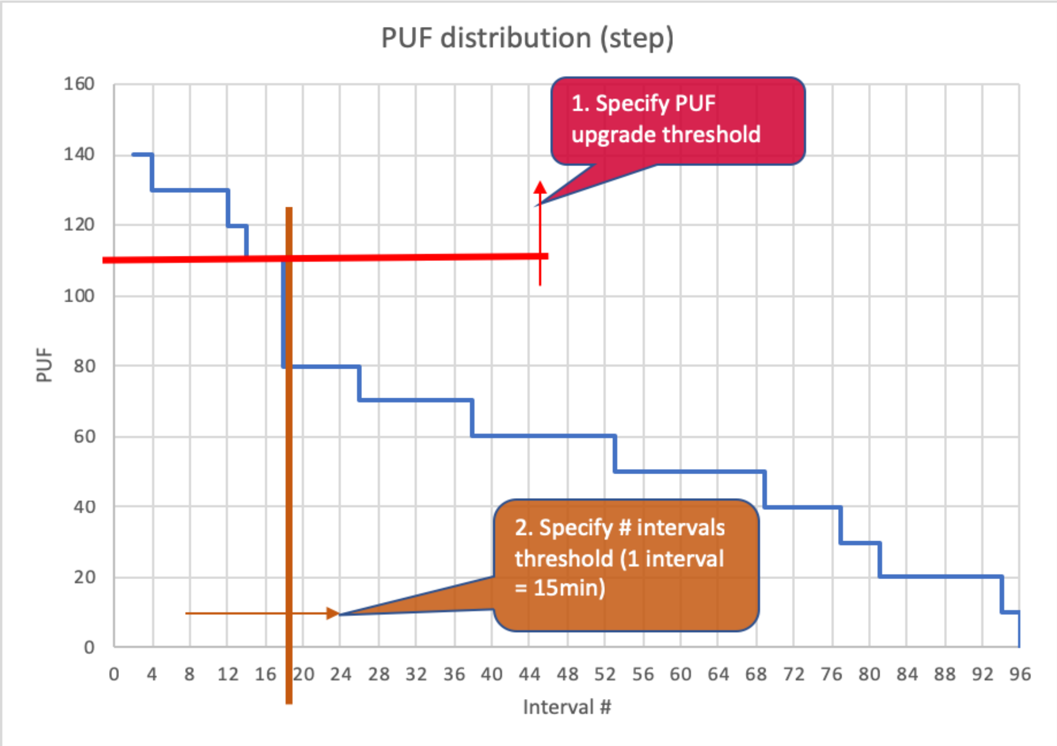

Figure 10: Threshold Limits for Short Listing Substations for upgrading

AusNet Services uses the following thresholds for managing distribution transformers:

- Monitor: Eighth interval (2 hour) is greater than 140%
- Act: Eighth interval (2 hour) is greater than 150% (based on AS/NZS 60076.7:2013 Table 4; refer Figure 11)

Distribution substations exceeding 140%PUF will be shortlisted for upgrade and projects will be initiated when their utilisation exceeds 150%.

Table 4 – Current and temperature limits applicable to loading beyond nameplate rating

Types of loading	Distribution transformers (see Note)	Medium power transformers (see Note)	Large power transformers (see Note)
Normal cyclic loading			
Current (p.u.)	1,5	1,5	1,3
Winding hot-spot temperature and metallic parts in contact with cellulosic insulation material (°C)	120	120	120
Other metallic hot-spot temperature (in contact with oil, aramid paper, glass fibre materials) (°C)	140	140	140
Top-oil temperature (°C)	105	105	105
Long-time emergency loading			
Current (p.u.)	1,8	1,5	1,3
Winding hot-spot temperature and metallic parts in contact with cellulosic insulation material (°C)	140	140	140
Other metallic hot-spot temperature (in contact with oil, aramid paper, glass-fibre materials) (°C)	160	160	160
Top-oil temperature (°C)	115	115	115
Short-time emergency loading			
Current (p.u.)	2,0	1,8	1,5
Winding hot-spot temperature and metallic parts in contact with cellulosic insulation material (°C)	See 7.2.1	160	160
Other metallic hot-spot temperature (in contact with oil, aramid paper, glass fibre materials) (°C)	See 7.2.1	180	180
Top-oil temperature (°C)	See 7.2.1	115	115
NOTE The temperature and current limits are not intended to be valid simultaneously. The current may be limited to a lower value than that shown in order to meet the temperature limitation requirement. Conversely, the temperature may be limited to a lower value than that shown in order to meet the current limitation requirement.			

Figure 11: AS/NZS 60076.7 Table 4

B.2 Future Forecast

To forecast the number of substations to be upgraded during the next EDPR period from 2021 to 2025 the following assumptions were made:

- Average demand load growth from 2019 to 2020 was assumed 1.5% per year
- Average demand load growth from 2021 to 2025 was assumed to be 3% per year
- Substations with less than 9 customers were removed from the analysis
- Substations with a rating of less than 65 kVA were removed from the analysis
- Data issues such as customer cross referencing and incorrect transformer rating plate information in SAP lead to inaccuracy of the results of 40% (i.e. estimates from the PUF tool are reduced by 40% to determine the actual replacement forecast)

Table 11 shows the number of distribution substations identified in the initial analysis over the next EDPR period, based on the above assumptions, prior to an adjustment for data issues. It shows the number of substation exceeding 140% PUF and 150% PUF.

Table 11: Estimated number of overloaded distribution transformers by 2025

PUF	2021	2022	2023	2024	2025
>=140 PUF	270	314	363	395	404
>=150 PUF	186	228	255	298	349

Table 12 gives the results of adjusting for data issues to determine the estimated number of transformers requiring replacement by 2025.

Table 12: Estimated number of overloaded distribution transformers by 2025 with correction factor

PUF	2021	2022	2023	2024	2025
>=140 PUF	162	188	218	237	242
>=150 PUF	112	137	153	179	209

Assuming a replacement cost of [C.I.C]per transformer, gives a forecast expenditure of [C.I.C] million.