DISTRIBUTION ANNUAL PLANNING REPORT

December 2025

Disclaimer

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

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

This Distribution Annual Planning Report (**DAPR**) has been prepared in accordance with the National Electricity Rules (**NER**), in particular Schedule 5.8, as well as meeting the requirements of the (**DSPR**) Distribution System Planning Report required by the Victorian Electricity Distribution Code of Practice (**VEDCoP**) Section 19.4.

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

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1 Executive summary

This Distribution Annual Planning Report (**DAPR**) provides an overview of the current and future changes that United Energy proposes to undertake on its network. It covers information relating to 2025, as well as the forward planning period for this DAPR of 2026 to 2030.

United Energy is a regulated Victorian electricity distribution business. United Energy distributes electricity to more than 720,000 customers across east and south-east Melbourne and the Mornington Peninsula, where the vast majority of the customers are residential and located in urban areas. The network consists of more than 202,000 poles and 13,500 kilometres of overhead lines and underground cables. Electricity is received via 92 sub-transmission lines at 47 zone substations, where it is transformed from sub-transmission voltages to distribution voltages.

The DAPR sets out the following information:

- import capacity and associated maximum demand forecasts, and export capacity and associated minimum demand forecasts at the zone substation, sub-transmission and primary distribution feeder levels;
- system limitations resulting from the forecast maximum demand breaching its import capacity, or from the forecast minimum demand breaching its export capacity, following forced outages, retirements or asset de-ratings;
- projects that have been, or will be, assessed under the Regulatory Investment Test for Distribution (**RIT-D**); and
- other high-level information providing context for United Energy's planning processes and activities.

The DAPR provides a high-level description of the balance that United Energy will take between investing in augmentation and replacement of its assets over the forecast period, with network risk, performance, and compliance outcomes and requirements. Transmission connection assets supplying the distribution network are addressed in a separate report called the Transmission Connection Planning Report (**TCPR**)[1].

Information presented within this DAPR may indicate an emerging limitation where a more detailed analysis of risks and options for remedial action by United Energy are required. These emerging limitations are potential opportunities for prospective proponents to provide alternative non-network solutions to address the network need, at the identified zone substations, sub-transmission loops and primary distribution feeders. The DAPR also provides preliminary information on distribution substation and low-voltage circuit limitations as part of our consultation obligations under the Demand Management Incentive Scheme (**DMIS**).

[1] The Transmission Connection Planning Report is available on the United Energy website at https://www.unitedenergy.com.au/network-management/network-planning/network-data

Network limitation information is also provided in MS-Excel® format, within the System Limitations Template accompanying this report. Providing this information to the market, facilitates the efficient development of the network by broadening the range of options available, to best meet the needs of customers.

The DAPR is aligned with the requirements of Clauses 5.13.2(b) and (c) of the National Electricity Rules (**NER**) and contains the detailed information set out in Schedule 5.8 of the NER. In addition, the DAPR contains information consistent with the requirements of Section 19.4 of the Victorian Electricity Distribution Code of Practice (**VEDCoP**), as published by the Essential Services Commission of Victoria (**ESC**).

1.1 Public consultation

United Energy invites written submissions from interested parties to offer alternative proposals to defer or avoid the proposed works associated with the identified network limitations. All submissions should address the technical characteristics of non-network options provided in this DAPR and include information listed in United Energy's Demand Side Engagement (**DSE**) Document[2].

We also welcome feedback or suggestions for improvement on the structure or content presented in this year's DAPR, System Limitations Template or Distribution Voltage Information template.

All written submissions or enquiries should be directed to planning@ue.com.au.

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

United Energy
Attention: Head of Network Planning
Locked Bag 14090
Melbourne VIC 8001

[2] The Demand-Side Engagement Document is available on the United Energy website at https://media.unitedenergy.com.au/factsheets/UE-PL-2202-Demand-Side-Engagement-Document.pdf

2 Background

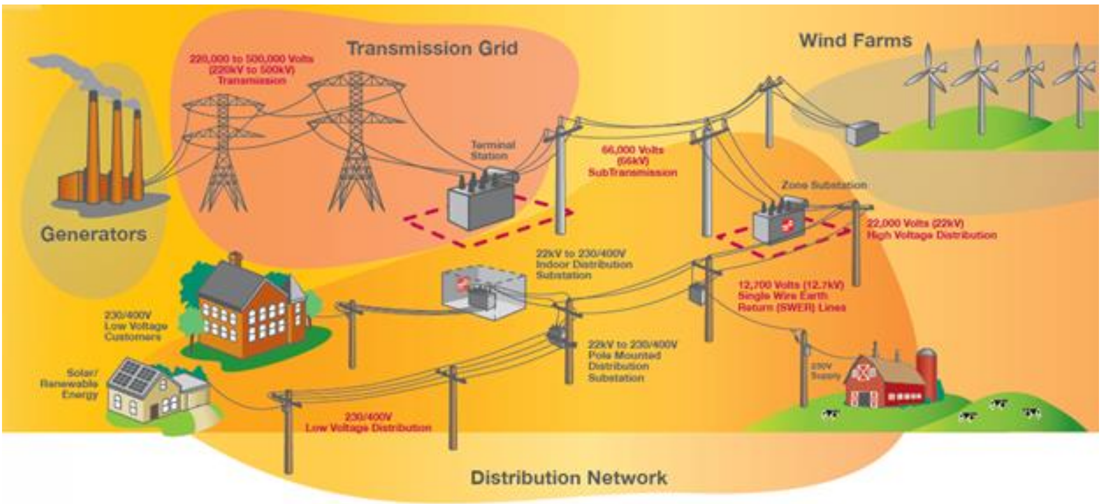
This chapter sets out background information on United Energy Distribution Pty. Ltd. (**United Energy**) and how it fits into the electricity supply chain.

2.1 Who we are

United Energy is a regulated Distribution Network Service Provider (**DNSP**) within Victoria. United Energy owns the poles, wires and substations which supply electricity to homes and businesses.

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

Figure 2.1 The electricity supply chain



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

- **Generation**: generation companies produce electricity from sources such as coal, gas, hydro, wind or sun, and then compete to sell it in the wholesale National Electricity Market (**NEM**). The market is overseen by the Australian Energy Market Operator (**AEMO**), through the co-ordination of the interconnected electricity systems of Victoria, New South Wales, South Australia, Queensland, Tasmania and the Australian Capital Territory.
- **Transmission**: the transmission network transports electricity from centralised generators at high-voltage, to five Victorian distribution networks. Victoria's transmission network also connects with the grids of New South Wales, Tasmania and South Australia.
- **Distribution**: distributors such as CitiPower, Powercor and United Energy convert electricity from the transmission network into lower voltages and deliver it to Victorian homes and businesses. The major role of DNSPs is in developing and maintaining their networks to ensure a safe, reliable supply of electricity is delivered to customers, to the required quality of supply standards.

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

2.2 The five Victorian distributors

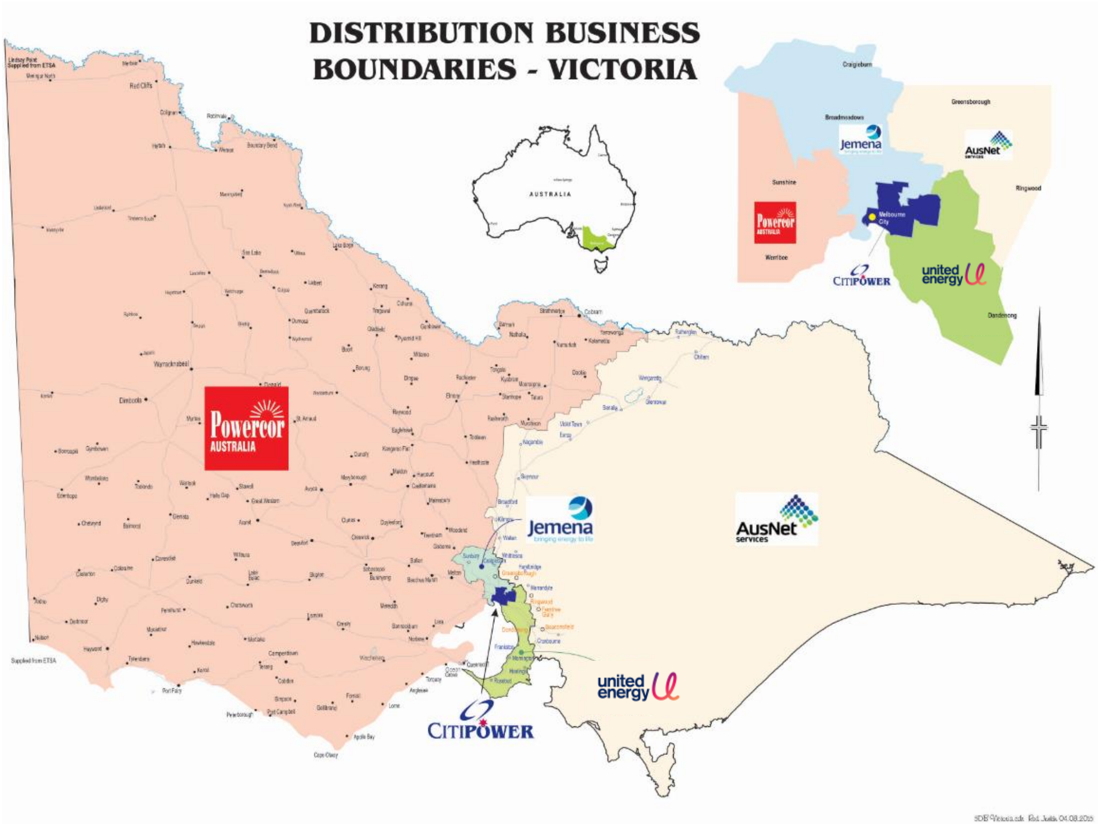
In the distribution stage of the supply chain, there are five businesses operating in Victoria. Each business owns and operates the electricity distribution network in a prescribed geographic area. United Energy is one of those distribution businesses.

The United Energy distribution network transports electricity to customers in Melbourne's southeast and the Mornington Peninsula. United Energy's service area is largely urban and semi-rural, and although geographically small (about one percent of Victoria's land area), it accounts for around one-quarter of Victoria's population and one-fifth of Victoria's electricity maximum demand. In particular, the service area consists of:

- the northern region, which is a leafy developed urban area in metropolitan Melbourne, bounded by the AusNet Electricity Services and CitiPower service areas, and Port Phillip Bay. The area includes predominantly residential and commercial centres such as Box Hill, Caulfield, Doncaster and Glen Waverley, with light industrial centres such as Braeside, Clayton, Heatherton, Mulgrave and Scoresby;
- the central region, being a mix of developed and undeveloped land. It includes the industrial and commercial centre of Dandenong, and many of United Energy's greenfield growth areas such as Keysborough, Lyndhurst and Bangholme; and
- the southern region, from Frankston down to Hastings and Portsea. Frankston denotes the southern rim of the Melbourne metropolitan area and is the gateway to the Mornington Peninsula. Frankston is one of the largest retail areas outside of the Melbourne CBD. The Mornington Peninsula is a 720 square kilometre boot-shaped promontory separating two contrasting bays: Port Phillip and Western Port. The Mornington Peninsula is surrounded by the sea on three sides, with coastal boundaries of over 190 kilometres.

The coverage of United Energy's service area relative to the other Victorian DNSPs is shown in Figure 2.2.

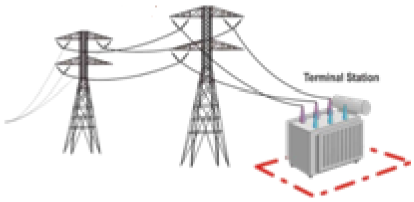
Figure 2.2 United Energy distribution service area



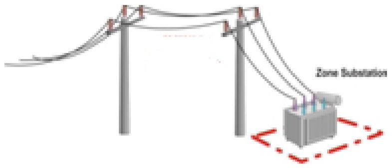
In Victoria, each DNSP has responsibility for planning the augmentation of their distribution network and the associated transmission connection assets. DNSPs are also responsible for the lifecycle management of their assets including asset replacements and retirements. In order to continue to provide an efficient, safe and reliable supply to its customers, United Energy must plan for the augmentation and replacement expenditure needs of the network. The need for augmentation is largely driven by customer maximum demand growth and geographic shifts of demand due to urban redevelopment. The need for replacement is largely driven by asset condition, safety and performance.

2.3 Delivering electricity to customers

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

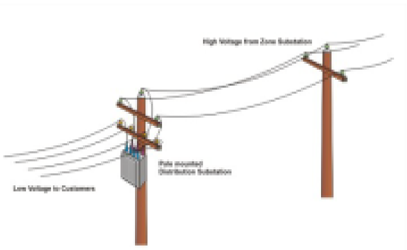


Firstly, the voltage of the electricity that is delivered by transmission at 220,000 Volts (220kV), is reduced by transformers within **terminal stations** down to 66kV or 22kV. The United Energy network is supplied from the transmission connection assets within these terminal stations.



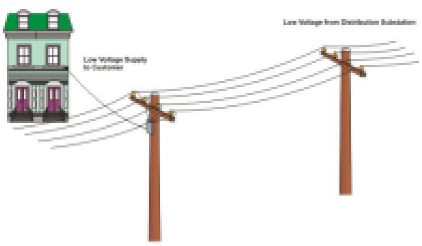
Secondly, United Energy transports the electricity from the terminal stations through its **sub-transmission network**, made up of large power poles, overhead lines and underground cables, to its zone substations.

Thirdly, at the **zone substation** the electricity voltage is converted by transformers down to 22kV, 11kV or 6.6kV. Electricity at this voltage can then be distributed throughout the service area on distribution feeders.



Fourthly, **high-voltage distribution lines** (distribution feeders) transfer the electricity from the zone substations to United Energy's distribution substations.

Furthermore, electricity is transformed down to 400 Volts (3-phase) or 230 Volts (single-phase) at the **distribution substations,** being at a voltage level suitable for supply to customers.



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

Traditionally, the flow of electricity has been from large-scale generators (connected at the transmission or sub-transmission level) to the low-voltage network. For more than a decade, our customers are also installing increasing amounts of Distributed Energy Resources including solar photovoltaic, batteries and electric vehicles in their homes and businesses. These Distributed Energy Resources are now producing electricity locally at the low-voltage level and exporting it back into the network.

2.4 Operating environment and asset statistics

United Energy delivers electricity to approximately 720,000 homes and businesses in a 1,472 square kilometre service area, around 489 customers per square kilometre.

United Energy's customer base is mainly residential across its urban and semi-rural service area.

The United Energy electricity network comprises a sub-transmission network which consists of predominantly overhead lines that operates at 66kV (with some at 22kV), and a distribution network that operates at voltages of 22kV and 11kV (with some at 6.6kV). The overall network consists of approximately 74 per cent overhead lines and 26 per cent underground cables.

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

The majority of the sub-transmission network nominally operates at 66kV and is generally configured in loops or in mesh to maximise reliability. The sub-transmission network operates at 22kV on some lines from the Malvern terminal station.

The sub-transmission network supplies electricity to zone substations which then transform (step down) the voltage suitable for the distribution to the local areas.

The high-voltage distribution network consists of both overhead and underground lines connected to substations, switchgear, and other equipment providing effective protection and control. The majority of the high-voltage distribution network nominally operates at 22kV and 11kV. There are some notable exceptions:

- the high-voltage distribution feeders from the Surrey Hills zone substation operate at 6.6kV;
- the high-voltage distribution feeders at West Doncaster zone substation are at voltages of 11kV and 6.6kV; and
- a small Single Wire Earth Return (**SWER**) system supplying some customers in the Mornington Peninsula, operates at 12.7kV.

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

The final supply to most consumers is provided through the low-voltage distribution systems that nominally operate at 230 (single-phase) or 400 (3-phase) Volts. These voltages are derived from "distribution substations" which are located throughout the distribution network. The majority of United Energy's low-voltage network is overhead, however reticulations to new residential housing estates are typically underground. The low-voltage reticulation (including service arrangements) completes the final connections to the low-voltage customer points of supply.

The United Energy network maximum demand and asset statistics as at 30 June 2025, are presented in Table 2.1.

Table 2.1 United Energy network statistics

Item	Value
Peak coincident demand (summer 2024-25)	1,953 MW
Record peak coincident demand (summer 2008-09)	2,084 MW
Poles	202,667
Overhead lines	9,997 km
Underground cables	3,557 km
Sub-transmission lines	79
Zone substation transformers	116
Distribution feeders	460
Distribution transformers	14384

Appendix A provides a map which shows the location of United Energy's zone-substation assets and the connected terminal stations on a geographic basis.

3 Factors impacting the network

This chapter sets out the factors that have a material impact in driving network limitations within the United Energy distribution network. These include:

- **maximum demand**: increases in electricity maximum demand levels can result in thermal capacity limitations, such as that caused by new residential customers connecting to the network (population growth), or new or changed business requirements for electricity;
- **minimum demand**: increases in reverse power flows (observed as negative demand) can result in thermal capacity limitations, such as that caused by new embedded generators connecting to the network;
- **fault levels**: changes in short-circuit levels resulting in switchgear rupture limitations or unsafe step-and-touch potentials (for example), such as that caused by some types of embedded generation being connected to the network;
- **voltage levels**: changes in steady state voltage levels resulting in voltage compliance limitations, due to changes in power flow through network impedances. Examples include lower voltages caused by increased power demand between voltage regulating equipment and customer load at maximum demand, or higher voltages contributed by solar photovoltaic (**PV**) systems exporting into the network at minimum demand, reversing the direction of power flows;
- **system security and reliability**: changes that may impact either system security for AEMO, such as the connection of embedded generation or changes in protection systems, or reliability such as changes in the configuration and sectionalisation of the network, or its operating environment;
- **quality of supply**: changes in quality of supply such as that caused by the connection of new customer equipment. United Energy may carry out system studies on a case-by-case basis as part of the customer connection process; and
- **asset condition**: changes in asset condition over time which may lead to unreliable assets, such as deterioration caused by ageing, exposure to short-circuit currents, or adverse environmental conditions.
- **system strength locational factor**: The system strength locational factor represents the electrical distance of the embedded generation connection point to the system strength node.

These factors are discussed in more detail below.

3.1 Maximum demand

At present, increases in maximum demand on the electricity network drives essentially all of the thermal capacity limitations and some of the voltage limitations observed on United Energy's network. Maximum demand is influenced by a range of factors including:

- **population growth**: increases in the number of residential customers connecting to the network;
- **economic growth**: changes in the demand from small, medium and large businesses, and large industrial customers;
- **retail prices**: changes in the retail price of electricity influences the demand for electricity from the network; and
- **extreme weather**: the effect of ambient temperature extremes on demand largely due to increasing use of cooling (and heating) appliances, such as reverse cycle air-conditioners.
- **electrification of gas:** the substitution of electrical loads for gas over time will increase loading on the electrical system adding to maximum demand – a trend accelerated by the Victorian Government's Gas Substitution Roadmap and gas ban on new connections from 1 Jan 2024.

Further increases in maximum demand is expected over the short to medium horizon with increased uptake of Electric Vehicles (EV) and electrification of customer loads.

3.2 Minimum demand

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

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

Forecasting of demand is discussed further in Chapter 5.

3.3 Fault levels

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

Recently a number of Zone Substations have been equipped with Rapid Earth Fault Current Limiters REFCLs (see section 3.8 below). These have the effect of considerably reducing phase to ground fault levels when they are in service. Regardless, the system still needs to be able to operate within fault level limits if for any reason the REFCL's are out of operation.

United Energy calculates the prospective fault current level, to ensure it is within allowable limits of the electrical equipment installed, and to enable the selection and setting of the protective devices can detect a fault condition. Devices such as circuit breakers, automatic circuit reclosers, sectionalisers, and fuses can act to interrupt the fault current to protect electrical plant, avoiding significant and sustained outages resulting from plant damage.

Fault-levels are influenced by a number of factors including:

- generation of all sizes, but particularly non-inverter based systems;
- impedance of transmission and distribution network equipment;
- earthing arrangements;
- load, including motors; and
- voltage level.

The following fault-level limits generally apply to the United Energy distribution network:

Table 3.1 Fault-level limits

Voltage	Fault-level Limit
66kV	21.9 kA
22kV	13.1 kA
11kV	18.4 kA
6.6kV	21.9 kA
<1kV	50.0 kA

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

There are presently no fault level limitations within United Energy's network that require corrective action.

3.4 Voltage levels

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

DNSPs are obligated to maintain customer voltages within limits prescribed by the VEDCoP, and these are further discussed in Chapter 17 of this DAPR. Similarly, manufacturers only supply appliances and equipment that operate within the Australian

Standards. Supply voltage at levels outside these limits, could affect the performance of (or cause damage to) this equipment.

Voltage levels are influenced by a number of factors including:

- impedance of transmission and distribution network equipment;
- load levels and power factor;
- distributed generation, such as household solar PV systems;
- tap position of transformers in the network; and
- capacitor banks within the network.

United Energy manages the voltage variations caused by changes in power flows through the network impedance between the customer and the supplying substations, using its voltage regulating equipment and capacitor banks.

Over the last decade, increasing uptake of solar PV systems by customers is causing higher voltage levels in localised areas of the network while they export. In response to this broader uptake of solar PV across the network and its impact on voltage levels, United Energy established a network-wide Dynamic Voltage Management System (**DVMS**). This system provides closed-loop voltage control using AMI smart meters as the source of customer voltage information, to control low-voltage network voltages using the zone substation voltage regulation equipment. This system is now in operation to continuously monitor and manage network voltages, accommodating greater levels of solar PV connections to United Energy's network. Refer to Section 17.4.1 for further details. In parallel to the operation of the DVMS, United Energy monitors low-voltage network voltages using AMI smart meter analytics tools, to identify any residual network voltage limitations not addressed by the DVMS, for possible localised mitigation solutions.

3.5 System security and reliability

AEMO is responsible for managing the overall security of the power system. Embedded generation and protection systems within the distribution network influence the overall stability of the power system. United Energy undertakes joint planning with AEMO and VicGrid to ensure that the United Energy distribution network (and the loads and generators connected within it), is planned, protected and operated in a manner that contributes to the security of the power system.

In order to maintain system stability for a major loss of generation, AusNet operate an under-frequency load shedding scheme (UFLS). This scheme operates to shed load at the sub-transmission level if a sudden loss of frequency is experienced, preventing a cascading event leading to system black. With the advent of generation at the sub-transmission network level as well as on the HV and LV networks, the load available to the existing UFLS is reducing, meaning this scheme is increasingly unable to shed load without also shedding generation affecting its viability. As a result, United Energy is proposing to embark on a program to install UFLS at the zone substation level to enable discrimination with generation and ensure proper operation of the scheme.

United Energy is responsible for the reliability of its distribution network. Changes in the configuration and sectionalisation of the network, or its operating environment influence the reliability performance outcomes of the network. For example, network augmentation or network performance projects are likely to result in reliability improvements for customers in the parts of the network affected.

3.6 Quality of supply

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

3.7 Asset condition

The age profile of United Energy's distribution network assets reflects the large investment that took place in the electricity networks in Victoria, with much of the area electrified post-world wars. Assets on the United Energy network were first installed in Melbourne in the early part of the 1900s, although it wasn't until the late 1930s that network assets were being installed in large numbers. From the late 1950s the United Energy network started growing rapidly, with a large number of new customer connections driven by the economic growth in the post-war decades.

During the latter part of last century and in the first decade of the current, the capacity of the network continued to grow with new and infill residential and business developments, growth in air-conditioning, computers, home entertainment systems, and other household appliances, all contributing to significant maximum demand growth across the network.

The cycles of investment in network augmentation, means that there is a wide variation in the age of assets in service within the United Energy network. The growing proportion of aged assets reflects the uneven historical development of the network. The present implication is that an increasing number of assets are approaching their end-of-life and are likely to require replacement over the current and future forward-looking planning periods.

The relationship between asset age and the probability of asset failure is well known. Assets typically have a long period of serviceable life with a low failure rate, followed by a period of deterioration, leading to increasing failure rates.

The failure characteristics will differ across asset categories. However, the generally accepted principle is that asset failure rates typically accelerate as assets approach their end-of-life; the rate of which can vary from asset to asset and is affected by various factors including operating conditions and the environment. If an increasing proportion of assets is approaching the time period where the failure rate starts to increase, the risk of asset failures across the network increases.

United Energy anticipates and manages this risk via a wide range of asset management tools and techniques to assess the condition of network assets. This information is used to drive a range of further activities including more frequent maintenance, asset replacement or alternative mitigation activities based on the results. This program aims to ensure that the asset remains safe and functional, whilst maximising asset life and focussing on a condition-based approach.

United Energy's strategy is to maintain reliability and network safety efficiently by complementing asset replacement with other strategies. For further details on United Energy's asset management approach and replacement projects, please refer to Chapters 13, 14 and 15.

3.8 Rapid Earth Fault Current Limiters (REFCLs)

This section sets out United Energy's plans to install Rapid Earth Fault Current Limiters (REFCLs) in the network. The purpose of installing REFCLs is to provide safety and reliability benefits to the community through reduced risk of electrical asset failures.

3.8.1 Zone Substations

The table below shows the zone substations on the United Energy network that have a REFCL system installed.

Zone substations		
Dromana (**DMA**)	Frankston South (**FSH**)	Mornington (**MTN**)

United Energy currently have no plans to install REFCL devices at other zone substations on the network.

3.8.2 Other impacted areas of the network

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

New or existing HV customers connected to the feeders listed below, which may experience a REFCL condition during contingent events, are also required to take action to ensure that their assets are compatible with the operation of a REFCL

Non-REFCL Feeders Hardened for REFCL			
FTN11	FTN14	FTN22	LWN21

LWN22	LWN23	LWN24	LWN32
LWN33	LWN34	LWN35	RBD12 (Part)
RBD13 (Part)	RBD21 (Part)	RBD22 (Part)	HGS22
HGS23 (Part)	HGS33	LD33 (Part)	MGE32 (Part)

3.9 Distribution System Operator (DSO) enhanced capability

To respond to the future challenges of the network for least cost it is recognised that United Energy needs to implement and support new capabilities under an enhanced DSO role. IT investments in this area have been articulated in Chapter 19. These capabilities are broadly around the workstreams of:

- Enabling distributed energy resources export and increasing hosting capacity whilst addressing minimum demand and other system security obligations that may be placed on the DNSP;
- Utilising batteries to manage constraints and value stacking arrangements with third-parties to demonstrate multiple benefits;
- Enabling competition for non-network solutions through expanded platforms for sharing network constraints;
- Develop Dynamic Operating Envelope capability that is flexible to more dynamically manage the network and enable third-party service offerings on the distribution network

Chapter 18 details the specific projects that United Energy is delivering in terms of demand management and non-network solutions.

3.10 System Strength Locational Factor

In October 2021, the AEMC made its final rule determination on efficient management of system strength on power system. The Rule introduces a new way for system strength remediation in the NEM, allowing the embedded generators to either pay for system strength charges or self-remediation. The system strength locational factor represents the electrical distance of the embedded generation connection point to the system strength node (a location on a transmission network that AEMO declares under NER clause 5.20C.1(a)) and is used to calculate the system strength charge in accordance with the methodology in the AEMO's System Strength Impact Assessment Guidelines[3].

Under NER Schedule 5.8 (q), the system strength location factor information for each embedded generation (or generating system) in United Energy network in which the

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

embedded generation system has elected to pay the system strength charge under clause 5.3.4B(b1) is to be included in this report.

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

4 Network planning standards for augmentations

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

4.1 Approaches to planning standards

In general, there are two different approaches to network planning:

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

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

- under a probabilistic approach, there are conditions under which all the load cannot be supplied (or some generation needs to be curtailed) with a network element out of service (hence the N-1 criterion is not met); however
- the EUE may be very small relative to the cost of alleviating the limitation, after considering the low probability of a forced outage of a particular element of the network.

The probabilistic approach also assesses EUE under system normal conditions (known as the "N" condition). This is where all assets are operating but the demand breaches either the total import or export capacity. Contingency load transfers or a non-network solution may be used to mitigate the risk in the interim period until it is economically viable for an augmentation to be completed.

4.2 Application of the probabilistic approach to planning

United Energy adopts a probabilistic approach to its planning including its zone substation, sub-transmission and primary distribution feeder asset augmentations.

The probabilistic planning approach involves estimating the probability of an asset outage occurring within a peak loading period, and:

- the EUE cost that will be incurred from expected supply interruptions if no action is taken to address an emerging limitation, and therefore

- whether it is economic to augment the network capacity to reduce expected supply interruptions.

The quantity and value of EUE (which is discussed in Chapter 6) is a critical parameter in assessing a prospective network investment or other action in response to an emerging limitation. Probabilistic network planning aims to ensure that an economic balance is struck between:

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

In other words, recognising that very extreme demand conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that a network asset outage occurs at the same time.

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

- the results of studies of possible outcomes, and the inherent uncertainty of those outcomes;
- the potential costs and other impacts that may be associated with very low probability events, such as single or coincident transformer outages at times of maximum or minimum demand, and catastrophic equipment failure leading to extended periods of plant non-availability; and
- the availability and technical feasibility of cost-effective contingency plans and other arrangements for management and mitigation of risk.

5 Forecasting demand

This chapter sets out the method and assumptions for calculating historical and forecast levels of demand for each existing zone substation, sub-transmission system and primary distribution feeder. The spatial forecasts are used to identify potential future limitations in the network.

Please note that information relating to maximum and minimum demand forecasts at transmission-distribution connection points are provided in a separate report entitled the “Transmission Connection Planning Report” which is available on the United Energy website[4].

5.1 Maximum and minimum demand forecasts

United Energy has set out its forecasts for maximum demand for each existing zone substation, and sub-transmission system as follows:

- zone substation maximum demands and export capacity: refer to Max Demand Template;
- sub-transmission system maximum demands and export capacity: refer to Max Demand Template;
- zone substation minimum demands and export capacity: refer to Min Demand Template; and
- sub-transmission system minimum demands and export capacity: refer to Min Demand Template.

5.2 Zone substation methodology

This section sets out the method and inputs used to calculate the demand forecasts for the zone substations and related information that is set out in the Max Demand Template and Min Demand Template.

5.2.1 Historical demand

Historical demand is calculated in Mega Volt Ampere (**MVA**) and is based on actual transformer-summation, non-coincident maximum and minimum demand values recorded at each zone substation across the distribution network. Determining the actual maximum or minimum demand for each zone substation is first corrected for system abnormalities (i.e., load transfers, load-shedding, or generation curtailment).

As maximum and minimum demands are very weather dependent, the actual maximum and minimum demand values shown in Max Demand Template and Min Demand Template, are normalised in accordance with the relevant weather conditions experienced across any given period. Maximum demand is very dependent on the ambient

[4] https://www.unitedenergy.com.au/network-management/network-data/#distribution-annual-planning-report

temperature, whereas minimum daytime demand is very dependent on the amount of cloud cover. The weather-correction enables the historical, underlying maximum and minimum demand growth rate, to be estimated year-by-year. It also establishes a launch point from which to forecast future maximum and minimum demand growth.

The weather-correction for the maximum demand forecasts presented in this DAPR seeks to ascertain the "*10th percentile summer maximum demand*" or "*50th percentile summer maximum demand*". This 10th or 50th percentile demand represents the maximum demand on the basis of a normal season (summer and winter). It relates to a maximum average temperature that will be exceeded, on average, once every ten years for 10th percentile demand and two years for 50th percentile demand. It is often referred to as 10 per cent probability of exceedance (**10% PoE**) and 50 per cent probability of exceedance (**50% PoE**).

The weather-correction for the minimum demand forecasts presented in this DAPR seeks to ascertain the "*50th percentile annual minimum demand*". This 50th percentile demand represents the minimum demand on the basis of a weather condition that would lead to a one-in-two year minimum demand[5]. It is often referred to as 50 per cent probability of under-reach (**50% PoU**).

5.2.2 Forecast demand

The historical weather-corrected demand values are trended forward and combined with known or predicted loads or embedded generators that may be connected to (or disconnected from or transferred away to different parts of) the network. This includes taking into account customer connections and the estimated total output of known embedded generating units at a localised level.

United Energy has taken into account information relating to the load requirements of our customers, and the timing and diversification of those loads. This includes information of the estimated load requirements for planned, committed and under-construction developments across the United Energy service area, and large load planned retirements or reductions. United Energy has also taken into account information relating to DER installations by our customers.

These bottom-up forecasts for maximum demand have been reconciled (and scaled if necessary) with top–down econometric forecasts for United Energy as a whole, to ensure that historical trend forward is adjusted for changes at the macro-economic level and post-model adjustment disruptors (i.e., the maximum and minimum demand impacts of growth in solar PV, storage, EVs and energy efficiency).

5.2.3 Definitions for zone substation forecast tables

The Max Demand Template and Min Demand Template contains other details of relevance for each zone substation, including:

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[5] Consequently, there is also a 10% probability that demand will be lower than the minimum demand forecast.

- **Station N (import or export) rating**: this is the maximum cyclic capacity of the zone substation (for forward and reverse power flows respectively) assuming that the net load follows a daily pattern, with a rating calculated using load curves appropriate to the season, and that all equipment is in service, expressed in MVA;
- **Station N-1 (import or export) rating**: this is the cyclic capacity of the zone substation (for forward and reverse power flows respectively) with one transformer out-of-service that gives the lowest result, expressed in MVA. This is also known as the "firm" rating;
- **Hours load is ≥ 95% of maximum demand**: this is the total hours during the year that the zone substation net load is greater than or equal to 95 per cent of the maximum demand, given the annual load-duration curve;
- **Hours load is ≤ 95% of minimum demand**: this is the total hours during the year that the zone substation net load is less than or equal to 105 per cent of the minimum demand (if minimum demand is greater than zero) and less than or equal to 95 per cent of the minimum demand (if minimum demand is less than zero), based on the annual load-duration curve;
- **Station power factor at maximum or minimum demand:** this is the ratio of the active power to the apparent power at the times of maximum or minimum demand, noting this is negative if reactive power is being exported, irrespective of the direction of the active power flow;
- **Load transfer capability**: this is the forecast of the remaining capacity of adjacent zone substations and their adjacent feeder connections at times of maximum demand, available to take load away from the zone substation in emergency situations; and
- **Embedded generation capacity**: specified separately as both the total capacity of all embedded generation units greater than 1MW, and less than or equal to 1MW, that have been connected within the zone substation supply area at the date of this report.

5.3 Sub-transmission loops methodology

This section sets out the method for calculating the historical and forecast maximum and minimum demands for the sub-transmission loops and related information, that is set out in Max Demand Template and Min Demand Template.

5.3.1 Historical demand

The historical actual demand and weather-corrected 50% PoE and 50% PoU for maximum and minimum demands at the sub-transmission loops are calculated in a similar way to the zone substation method.

United Energy typically uses Amps to measure its sub-transmission line and loop demand and ratings, and these are converted to MVA in this DAPR and the Systems Limitations Template utilising the sub-transmission nominal voltage.

5.3.2 Forecast demand

The 50% PoE sub-transmission loop forecast maximum demand, is derived from the growth rate of the aggregated diversified 50% PoE forecast maximum demands of the zone substations contained within the sub-transmission loop. United Energy escalates the weather-corrected sub-transmission loop maximum demand, using this growth rate. A similar approach is applied for minimum demand. These forecasts are set out in the Max Demand Template and Min Demand Template.

5.3.3 Definitions for sub-transmission loop forecast tables

The Max Demand Template and Min Demand Template contains other details of relevance for each sub-transmission loop, including:

- **Loop N (import or export) rating**: this is the maximum capacity of the sub-transmission loop (for forward and reverse power flows respectively) with all lines in service, taking into account the load sharing of lines within the loop, expressed in MVA;
- **Loop N-1 (import or export) rating**: this is the capacity of the sub-transmission loop (for forward and reverse power flows respectively) with one line out-of-service that gives the lowest result, expressed in MVA[6];
- **Hours load is ≥ 95% of maximum demand**: this is the total hours during the year that the sub-transmission loop load is greater than or equal to 95 per cent of maximum demand, given the annual load-duration curve;
- **Hours load is ≤ 95% of minimum demand**: this is the total hours during the year that the sub-transmission loop load is less than or equal to 105 per cent of the minimum demand (if minimum demand is greater than zero) and less than or equal to 95 per cent of the minimum demand (if minimum demand is less than zero), based on the annual load-duration curve;
- **Power factor at maximum demand or minimum demand:** this is the ratio of the active power to the apparent power at the times of maximum or minimum demand, noting this is negative if reactive power is being exported, irrespective of the direction of the active power flow;
- **Load transfer capability**: this is the forecast of the remaining capacity of adjacent sub-transmission loops, their zone substations and adjacent feeder connections at times of maximum demand, available to take load away from the sub-transmission loop in emergency situations; and
- **Embedded generation capacity**: specified separately as both the total capacity of all embedded generation units that are greater than 1MW, and less than or equal to 1MW, that have been connected within the sub-transmission loop supply area at the date of this report.

5.4 Primary distribution feeders

This section sets out the method for calculating the forecast maximum and minimum demands for the primary distribution feeders.

[6] Note that a sub-transmission loop will have a different rating depending on which line is out of service. This is taken into account in any energy-at-risk assessment.

5.4.1 Forecast demand

Primary distribution feeder 50% PoE maximum and minimum demand forecasts presented in this DAPR are calculated in a similar way to forecasts for zone substations. The feeder historical weather-corrected maximum and minimum demand values are trended forward using the underlying zone substation growth rates. Individual feeders are adjusted for specific planned loads and embedded generation connecting to the feeder, making sure the aggregated feeders' forecast reconciles with the zone substation forecast.

5.5 Transmission-distribution connection points

This section sets out the method and inputs used to calculate the demand forecasts for the terminal stations and related information, that is set out in the Transmission Connection Planning Report (for maximum and minimum demands).

5.5.1 Historical demand

Historical demand is calculated in Mega Volt Ampere (**MVA**) and is based on actual transformer-summation, non-coincident maximum and minimum demand values recorded at each terminal station. Determining the actual maximum or minimum demand for each terminal station is first corrected for system abnormalities (i.e., load transfers, load-shedding, or generation curtailment).

As maximum and minimum demand are very weather dependent, the actual maximum and minimum demand values shown in the Transmission Connection Planning Report are normalised in accordance with the relevant weather conditions experienced across any given period. Maximum demand is very dependent on the ambient temperature, whereas minimum daytime demand is very dependent on the amount of cloud cover. The weather-correction enables the historical, underlying maximum and minimum demand growth rate, to be estimated year-by-year. It also establishes a launch point from which to forecast future maximum and minimum demand growth.

5.5.2 Forecast demand

The historical weather-corrected demand values are trended forward and adjusted for the changes in the zone substation growth rates of the zone substations connected to that terminal station.

5.5.3 Definitions for transmission-distribution connection point forecast tables

The Transmission Connection Planning Report contains other details of relevance for each terminal station, including:

- **Station N (import or export) rating**: this is the maximum cyclic capacity of the terminal station (for forward and reverse power flows respectively) assuming that the net load follows a daily pattern, with a rating calculated using net load curves appropriate to the season, and that all equipment is in service, expressed in MVA;

- **Station N-1 (import or export) rating**: this is the cyclic capacity of the terminal station (for forward and reverse power flows respectively) with one transformer out-of-service that gives the lowest result, expressed in MVA. This is also known as the “firm” rating;
- **Hours load is ≥ 95% of maximum demand**: this is the total hours during the year that the terminal station net load is greater than or equal to 95 per cent of maximum demand, given the annual load-duration curve;
- **Hours load is ≤ 95% of minimum demand**: this is the total hours during the year that the terminal substation net load is less than or equal to 105 per cent of the minimum demand (if minimum demand is greater than zero) and less than or equal to 95 per cent of the minimum demand (if minimum demand is less than zero), based on the annual load-duration curve;
- **Station power factor at (maximum or minimum) demand:** this is the ratio of the active power to the apparent power at the time of maximum or minimum demand, noting this is negative if reactive power is being exported, irrespective of the direction of the active power flow;
- **Load transfer capability**: this is the forecast of the remaining capacity of adjacent terminal stations and their adjacent feeder and sub-transmission connections at times of maximum demand, available to take load away from the terminal station in emergency situations; and
- **Embedded generation capacity**: specified separately as both the total capacity of all embedded generation units greater than 1MW, and less than or equal to 1MW, that have been connected within the terminal station supply area at the date of this report.

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

6 Approach to risk assessment

This chapter outlines the high-level process by which United Energy calculates the risk associated with potential shortfalls in network capacity over the forecast period for zone substations, sub-transmission lines and primary distribution feeders.

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

6.1 Energy-at-risk

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

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

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

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

For sub-transmission lines the same definition applies, however the failure rates and mean duration of an outage will differ. The failure rates and mean duration used for an outage of sub-transmission lines and zone substation transformers is discussed further in Section 6.5.

Although this DAPR focuses on presenting the energy-at-risk for a 50th percentile demand forecast (as discussed in Chapter 5), when undertaking an economic assessment of projects to address an identified need, United Energy moderates the energy-at-risk using a 30% and 70% weighting of the 10th and 50th percentile demand forecasts. Doing this takes into account the impacts of the year-on-year weather variability on energy-at-risk.

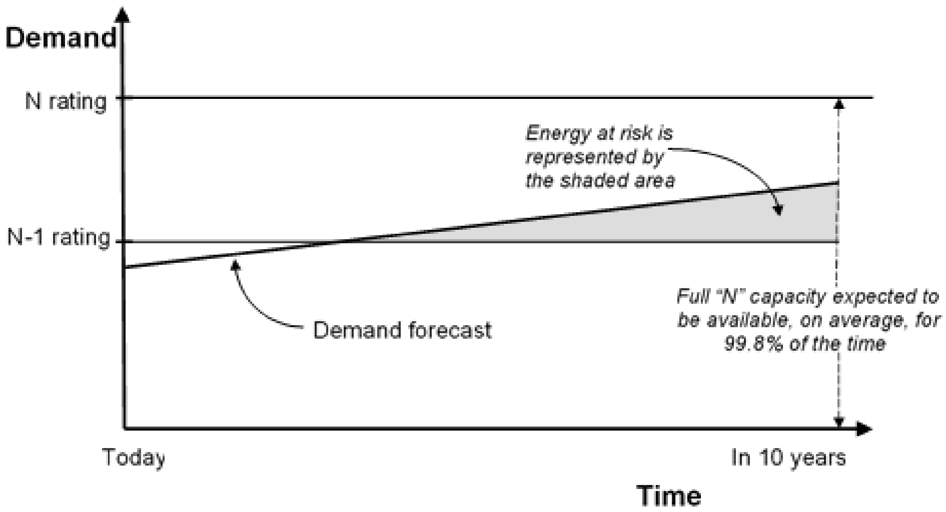
6.2 Interpreting energy-at-risk

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

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

The indicative relationship between the N and N-1 cycle ratings of a zone substation and the energy-at-risk (assuming maximum demand conditions), is depicted in Figure 6.1 below. The annual energy-at-risk is moderated by the load-duration curve of the demand, on the basis that the critical loading period only occurs for a small proportion of the year.

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



For augmentation projects and major replacement, United Energy undertakes a detailed assessment process to determine whether or not to proceed with the investment.

6.3 Value of customer reliability (VCR)

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

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

A rule change in July 2018 made the Australian Energy Regulator (**AER**) responsible for determining the values different classifications of customers place on having a reliable electricity supply. The AER subsequently developed an updated methodology for deriving Value of Customer Reliability (**VCR**) values and published new VCRs in December 2024. The applicable United Energy VCR values from this publication are as per Table 6.1 below:

Table 6.1 Values of customer reliability

Sector	VCR ($/kWh) $2024
Residential – Climate Zone 3 & 4 Regional	$24.86
Residential – Climate Zone 6 CBD & Suburban	$55.10
Residential – Climate Zone 6 Regional	$38.90
Residential – Climate Zone 7 CBD & Suburban	$50.72
Residential – Climate Zone 7 Regional	$35.69
Agricultural	$22.25
Commercial	$34.39
Industrial (<10MVA)	$33.49

These values are multiplied by the relative gross energy consumption weighting of each climate zone and sector applicable to the customer composition in the affected supply area, to estimate a composite single value of customer reliability for each supply area.

The composite VCR is used to calculate the economic benefit of undertaking an augmentation or replacement. When the net present value of the benefits outweighs the costs, and is superior to other options, United Energy is likely to proceed with the works.

6.4 Value of generation curtailment

On 12 August 2021, the AEMC made a final determination on its "Access, pricing and incentive arrangements for distributed energy resources" Rule change[7]. Under the Rule change, the AER is required to develop customer export curtailment values ("CECV"), which are an estimate of the detriment to customers and the market of export curtailment due to network limitations (in $ per kWh of exports curtailed). CECVs are expected to play a similar role to the VCR in evaluating the net benefit of reducing or removing network constraints. For instance, it is expected that the CECVs will be used to assess whether proposed steps to reduce export curtailment (such as increasing DER hosting capacity) can be economically justified.

In June 2022, the AER published its Customer Export Curtailment Value Methodology. At the same time, the AER also published a DER Integration Expenditure Guidance Note[8],

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

[8] Final decision | Australian Energy Regulator (AER)

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.

In June 2025, the AER published the updated CECV values for Victoria for the period 2025-2045[9], the updated values are based on the 2024-25 CECVs with an adjustment to account for inflation. United Energy relies on CECVs to guide decisions regarding network augmentation to increase solar hosting capacity. These values are summarised and illustrated in Figure 6.2 and Figure 6.3.

Figure 6.2 Average CECV across the year by year and time of day, $/MWh

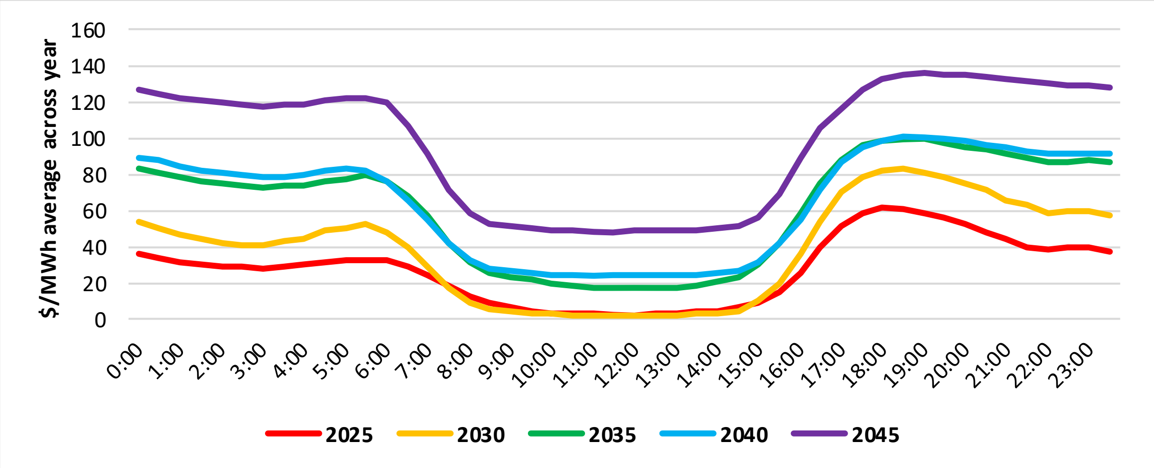
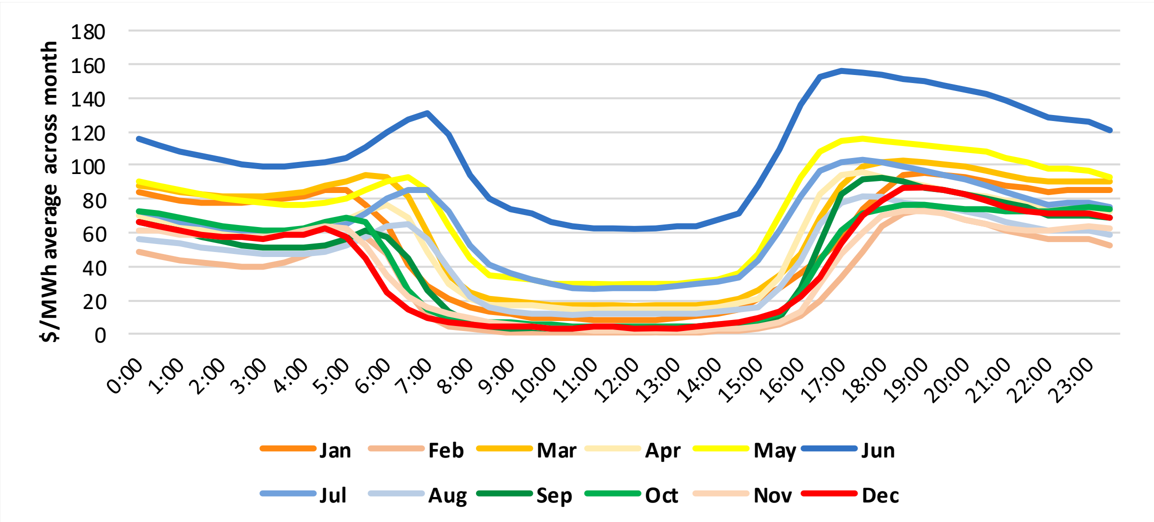


Figure 6.3 Average CECV by month and by time of day (2025-2045) $/MWh



[9] 2025 CECV - VIC | Australian Energy Regulator (AER)

The Oakley Greenwood 2024-25 CECV provides an indication of future benefit streams:

- Economic values follow a duck curve pattern throughout the period.
- The CECV is lowest during autumn and spring and remains relatively low in summer.

The highest values occur during the colder months (June, July, May, April, and August) due to lower irradiance levels.

6.5 Plant unavailability

The value of customer reliability (or the value of generation curtailment) is only one component in quantifying the cost of loss-of-supply risk for customers (or curtailment risk for embedded generators). United Energy combines these values with the expected unavailability of distribution network assets based on forced outage rates and outage durations.

The base (average) major fault reliability data adopted by United Energy for its augmentation assessments used in this DAPR and the Systems Limitations Template is shown in Table 6.2 and Table 6.3. The data is based on the Australian CIGRE Transformer Reliability Survey and United Energy's actual observed network performances. United Energy intends to update this data over time as more recent failure and repair time data become available from assets on the United Energy network.

Table 6.2 Zone substation transformer outage data

Major plant item: zone substation transformer		**Interpretation**
Transformer failure rate (major fault)	0.5% per annum	A major failure is expected to occur once per 200 transformer-years. Therefore, in a population of 100 zone substation transformers, for example, one major failure of any one transformer would be expected every two years.
Duration of outage (major fault)	2190 hours	A total of 3 months is required to repair / replace the transformer, during which time the transformer is not available for service.
Expected transformer unavailability per year	$\frac{Repair\ time}{Repair\ time + \frac{(24 \times 365)}{(failure\ rate\ )}}$	On average, each transformer would be expected to be unavailable due to transformer fault for 0.125% of the time or approximately 11 hours in a year.

Table 6.3 Sub-transmission line outage data

Major plant item: sub-transmission lines		Interpretation
Line failure rate (sustained fault)	4.8 faults per 100 km per annum	The average sustained failure rate of United Energy's sub-transmission lines is 4.8 faults per 100 km per year.
Duration of outage (sustained fault)	12 hours	On average 12 hours is required to repair an overhead line however cable faults can take considerably longer.
Expected line unavailability per year	$\frac{Repair\ time}{Repair\ time + \frac{(24\ \times 365)}{(failure\ rate\ \times length)}}$	On average, a 10 km sub-transmission line is expected to be unavailable due to a fault for about 0.066% of the time, or approximately 6 hours in a year.

In a detailed assessment process, all site-specific outage scenarios may also be considered. For example, a sub-transmission line forced outage may also cause a transformer to be taken out of service because of the switching arrangement at the zone substation. The base (average) outage data is also not applicable for replacement assessments which will consider asset-specific failure rates based on effective age and condition.

6.6 Value of expected energy-at-risk

The financial value of expected energy-at-risk is calculated by multiplying the "energy-at-risk", with the "plant unavailability", and either the "value of customer reliability" or the "value of generation curtailment", depending on whether the energy-at-risk is an import or export limitation.

7 Zone substations review

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

- Import limitations
  - forecasts for maximum demand to 2029-30; and
  - relevant seasonal cyclic N-1 ratings for each zone substation (firm import rating).
- Export limitations
  - forecasts for minimum demand to 2029-30; and
  - relevant cyclic N-1 export ratings for each zone substation (firm export rating).

Where the zone substations are forecast during 2025-26 to operate with 50% PoE maximum demand or 50% PoU minimum demand in breach of their firm import or export rating respectively, and the energy-at-risk is material, or if an augmentation project is planned, then this section assesses the energy-at-risk for those assets.

United Energy sets out possible options to address the system limitations. United Energy may employ the use of contingency load transfers to mitigate the system limitations although this will not always address the entire energy-at-risk at times of maximum or minimum demand. At other times, the available transfers may be greater. As a result, the use of transfers under contingency situations may imply an interruption of supply for customers or embedded generators to protect network elements from damage whilst all available load transfers take place.

Non-network providers may wish to review the limitations and consider whether alternative solutions (such as embedded generation, storage and demand management) to those augmentation programs set out in this section may be suitable. Solutions may also address sub-transmission limitations at the same time.

The annualised cost of the preferred network option provides a broad indication of the maximum potential value available to proponents of non-network solutions in deferring or avoiding network augmentation. However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation.

United Energy notes that all other zone substations that are not specifically mentioned below have maximum or minimum demand levels within the firm rating, or the demand is not more than 5% in breach of the relevant rating, resulting in negligible energy-at-risk.

Finally, new zone substations that are proposed to be commissioned during the forward planning period for this DAPR are also discussed.

Please note that all costings provided in this chapter are based on scoped estimates as of the specific point in time they were prepared. These variations reflect the timeframes and assumptions relevant to each project.

7.1 Zone substations with forecast limitations overview

Based on the analysis presented in Section 7.2 below, United Energy has determined that no augmentation will be undertaken to address system limitations during the five-year forward planning period for this DAPR.

Table 7.1 Proposed import-limited zone substation augmentations

Zone substation	Description	Direct cost estimate ($m)				
		2026	2027	2028	2029	2030
N/A	N/A	-	-	-	-	-

There are currently no identified export limitations during the five-year forward planning period for this DAPR. It should be noted that the export ratings currently used are thermal ratings only. Export ratings to accommodate reverse power flow should be assessed and determined based on all other system limitations such as voltage or any other secondary equipment limiting the export, which may necessitate the adoption of ratings that are less than the thermal rating. Work is underway to quantify the impacts of system limitations on export ratings. Until that work is finalised, thermal ratings are applied.

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

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

Our Dynamic Voltage Management System (DVMS) continues to actively manage voltage on our network. United Energy will continue to monitor the declining minimum demand levels on some of our zone substations and explore the feasibility of specific options to alleviate any forecast export limitations that cannot be managed by the DVMS, on a case-by-case basis.

The options and analysis are undertaken in the sections below.

7.2 Zone substations with forecast system limitations

7.2.1 Bentleigh (BT) zone substation

Bentleigh (**BT**) zone substation is served by sub-transmission lines from the Heatherton Terminal Station (**HTS**). It supplies the areas of Bentleigh, McKinnon, and parts of Ormond and Caulfield South.

Currently, BT zone substation consists of two 20/30MVA 66/11kV transformers.

The actual maximum demand at BT for summer 2024-25 was 32.54MVA. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26, there will be 2.1MVA of load-at-risk if there is a failure of a transformer at BT. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at BT zone substation. Consequently, an unplanned outage on one of the sub-transmission lines into BT would also result in an outage of one of the transformers at BT zone substation.

To address the anticipated system limitation at BT zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations North Brighton (**NB**) and Caulfield (**CFD**) up to a maximum transfer capacity of 6.1MVA;
- install a third 20/33MVA transformer at BT zone substation at an estimated cost of $9.0 million;
- install a third transformer at adjacent MR zone substation along with distribution feeders to offload BT (see Section 7.2.13), at an estimated cost of $12 million.

The least cost technically acceptable option is to install a third transformer at BT. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.2 Clarinda (CDA) zone substation

Clarinda (**CDA**) zone substation is served by sub-transmission lines from the Springvale Terminal Station (**SVTS**). It supplies the areas of Clarinda and Oakleigh South.

Currently, the CDA zone substation consists of one permanent 20/33MVA 66/22kV transformer and a 12/20MVA 66/22kV transformer.

The actual maximum demand at CDA for summer 2024-25 was 24.36MVA. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26, there will be 1.4MVA of load-at-risk if there is a failure of the permanent transformer at CDA. That is, it would not be able to supply all customers during high load periods following the loss of that transformer.

To address the anticipated system limitation at CDA zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Heatherton (**HT**), Springvale South (**SS**) and Notting Hill (**NO**) up to a maximum transfer capacity of 11.2MVA;
- Replace the existing 12/20MVA transformer with a second 20/33MVA transformer at CDA zone substation at an estimated cost of $7 million.

The least cost technically acceptable option is to install a new transformer at the CDA zone substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.3 Caulfield (CFD) zone substation

Caulfield (**CFD**) zone substation is served by sub-transmission lines from the Malvern Terminal Station (**MTS**). It supplies the suburbs of Caulfield, Malvern and Glenhuntly including the Monash University Caulfield Campus precinct. Currently, the CFD zone substation comprises two 20/33MVA 66/11kV transformers.

The actual maximum demand at CFD for summer 2024-25 was 50.89MVA which was above the N-1 ratings for the zone substation. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26, there will be 10.1MVA of load-at-risk if there is a failure of one of the transformers at CFD. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system limitation at CFD zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load via the distribution feeder network to adjacent zone substations of Bentleigh (**BT**), Gardiner (**K**), Elsternwick (**EL**), Ormond (**OR**) and East Malvern (**EM**) up to a maximum transfer capacity of 10.1MVA;
- install a third switchboard at adjacent zone substation East Malvern (**EM**), with 3 new distribution feeders to offload the load-at-risk at CFD zone substation, at an estimated cost of $15 million.

A number of surrounding adjacent zone substations to CFD including K and OR, and several feeders in the area are exhibiting load-at-risk. The least cost technically acceptable option to address these limitations, is to install a new switchboard with three new distribution feeders at the more lightly loaded EM zone substation.

The use of contingency load transfers will be used to mitigate the load-at-risk until this augmentation occurs.

7.2.4 Carrum (CRM) zone substation

Carrum (**CRM**) zone substation is served by sub-transmission lines from the Cranbourne Terminal Station (**CBTS**). It supplies the areas of Bangholme, Carrum, Carrum Downs, Chelsea, Patterson Lakes, Skye and Sandhurst.

Currently, CRM zone substation consists of three 20/33MVA 66/22kV transformers.

The actual maximum demand at CRM for summer 2024-25 was 75.30MVA. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26, there will be 6.7MVA of load-at-risk if there is a failure of a transformer at CRM. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system limitation at CRM zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations Dandenong Valley (**DVY**), Frankston (**FTN**), and Mordialloc (**MC**) up to a maximum transfer capacity of 16.6MVA;
- establish a new Skye (**SKE**) zone substation with new distribution feeders at an estimated cost of $30 million.

The least cost technically acceptable option is to establish a new SKE zone-substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.5 Doncaster (DC) zone substation

Doncaster (**DC**) zone substation is served by sub-transmission lines from the Templestowe Terminal Station (**TSTS**). It supplies the areas of Box Hill North, Doncaster, Doncaster East, Doncaster Hill and The Pines precincts, Templestowe and parts of the Box Hill central precinct.

Currently, the DC zone substation is comprised of two 20/27MVA 66/22kV transformers and one 20/30MVA 66/22kV transformer.

The actual maximum demand at DC for summer 2024-25 was 82.34MVA. Being designated as a Metropolitan activity centre by the Victorian Government under Plan Melbourne 2017-2050[10], the maximum demand in the Doncaster Hill and Box Hill areas is

[10] https://www.planmelbourne.vic.gov.au/

expected to continue to grow steadily over coming years. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26, there will be 7.8MVA of load-at-risk if there is a failure of one of the transformers at DC. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at DC zone substation. Consequently, an unplanned outage on one of the sub-transmission lines in the TSTS–DC–TSTS sub-transmission loop would also result in an outage of one of the transformers at DC zone substation.

In addition, all of the transformers at the zone substation are over 50-years of age with two of the three transformers in poor condition and have been assessed as being very close to end-of-life. United Energy is considering both the replacement and augmentation needs when developing a solution at DC in order to identify the lowest cost holistic solution.

To address the anticipated system limitation at DC zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Box Hill (**BH**) and Nunawading (**NW**) up to a maximum transfer capacity of 19.6MVA;
- install a fourth 20/33MVA transformer and one distribution feeder at DC zone substation at an estimated cost of $15 million.

The least cost technically acceptable long-term solution is to install a fourth transformer and one new feeder at DC. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The contingency load transfers will be used to mitigate the load-at-risk.

7.2.6 Elsternwick (EL) zone substation

Elsternwick (**EL**) zone substation is served by sub-transmission lines from the Malvern Terminal Station (**MTS**). It supplies the suburbs of Elsternwick and Caulfield.

Currently, the EL zone substation consists of one 20/27MVA 66/11kV transformer and one 20/33MVA 66/11kV transformer. The actual maximum demand at EL for summer 2024-25 was 32.64MVA. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26, there will be 1.9MVA of load-at-risk if there is a failure of one of the transformers at EL. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at EL zone substation. Consequently, an unplanned outage on one of the sub-transmission lines into EL would also result in an outage of one of the transformers at EL zone substation.

To address the anticipated system limitation at EL zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Caulfield (**CFD**), Elwood (**EW**) and North Brighton (**NB**) up to a maximum transfer capacity of 6.4MVA;
- install a third transformer at adjacent zone substations NB or EW along with distribution feeders to offload EL;
- install a third 20/33MVA transformer at EL zone substation at an estimated cost of $10.0 million.

The least cost technically acceptable solution is to install a third transformer at EL zone substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR.

In the interim, United Energy will utilise contingency load transfers to mitigate the load-at-risk.

7.2.7 Frankston South (FSH) zone substation

The Frankston South (**FSH**) zone substation is served by sub-transmission lines from the Tyabb terminal station (**TBTS**). It supplies the areas of Baxter, Frankston, Frankston South, Mount Eliza and Somerville.

Currently, the FSH zone substation comprises one 20/27MVA 66/22kV transformer and two 20/33MVA 66/22kV transformers.

The actual maximum demand at FSH for summer 2024-25 was 69.12MVA. Being designated as a Metropolitan activity centre by the Victorian Government[10], the maximum demand in the Frankston area is expected to continue to grow steadily over coming years. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26, there will be 10.9MVA of load-at-risk if there is a failure of one of the transformers at FSH. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there is a 66kV sub-transmission line circuit breaker on the MTN-FSH sub-transmission line, but not on the FTS–FSH sub-transmission line. Consequently, an unplanned outage on the FTS–FSH sub-transmission line would also result in an outage of one of the transformers at FSH zone substation.

To address the anticipated system limitation at FSH zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Frankston (**FTN**), Hastings (**HGS**), Langwarrin (**LWN**) and Mornington (**MTN**), up to a maximum transfer capability of 20.4MVA;

- replace the ageing FSH transformer No.1 with a modern equivalent which will increase the zone substation rating for an estimated cost of $5.0 million;
- install a new third 66/22kV transformer at adjacent Frankston (**FTN**) zone substation together with long distribution feeders to offload some of the load-at-risk at FSH zone substation; or
- establish a new 66/22kV zone substation at Somerville (**SVE**).

The least cost technically acceptable solution is to replace the aged FSH transformer No.1 with a modern equivalent (20/33MVA) transformer, so that the zone substation's summer (N-1) rating will be adequate to supply the maximum demand at FSH zone substation. However, given the economic cost of the limitation, this replacement is not currently expected in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.8 Frankston (FTN) zone substation

The Frankston (**FTN**) zone substation is served by sub-transmission lines from the Cranbourne terminal station (**CBTS**). It supplies the areas of Frankston, Frankston North, Seaford and Skye.

Currently, the FTN zone substation consists of two 20/33MVA 66/22kV transformers.

The actual maximum demand at FTN for summer 2024-25 was 51.0MVA. Being designated as a Metropolitan activity centre by the Victorian Government[10], the maximum demand in the Frankston area is expected to continue to grow steadily over coming years. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26, there will be 9.9MVA of load-at-risk if there is a failure of one of the transformers at FTN. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system limitation at FTN zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Carrum (**CRM**), Frankston South (**FSH**), and Langwarrin (**LWN**) up to a maximum transfer capacity of 18.6MVA;
- install a third 20/33MVA transformer at FTN zone substation at an estimated cost of $10 million;
- establish a new 66/22kV zone substation at Skye (**SKE**) with new distribution feeders.

The least cost technically acceptable option is to install a new transformer at the FTN zone substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR.

The contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.9 Hastings (HGS) zone substation

Hastings (**HGS**) zone substation is served by sub-transmission lines from the Tyabb terminal station (**TBTS**). It supplies the areas of Hastings, Merricks, Somerville and Tyabb.

Currently, the HGS zone substation consists of two 20/33MVA 66/22kV transformers.

The actual maximum demand at HGS for summer 2024-25 was 40.31MVA. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26 there will be 12.25MVA of load-at-risk if there is a failure of one of the transformers at HGS. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at HGS zone substation. Consequently, an unplanned outage on one of the sub-transmission lines into HGS would also result in an outage of one of the transformers at HGS zone substation.

To address the anticipated system limitation at HGS zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Frankston South (**FSH**), Langwarrin (**LWN**) and Mornington (**MTN**) up to a maximum transfer capacity of 14.6MVA;
- install a third 20/33MVA transformer at HGS zone substation at an estimated cost of $10 million;
- establish a new zone substation at Somerville (**SVE**).

The least cost technically acceptable option is to install a third 20/33MVA transformer at HGS zone substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.10 Gardiner (K) zone substation

Gardiner (**K**) zone substation is served by sub-transmission lines from the Richmond terminal station (**RTS**). It supplies the areas of Glen Iris and Malvern. Currently, the K zone substation consists of two 20/30MVA 66/11kV transformers operating at 66/11kV.

The actual maximum demand at K for summer 2024-25 was 37.22MVA. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26 there will be 3.6MVA of load-at-risk if there is a failure of one of the transformers at K. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at K zone substation. Consequently, an unplanned outage on one of the sub-transmission lines into K would also result in an outage of one of the transformers at K zone substation.

To address the anticipated system limitation at K zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load via the distribution feeder network to adjacent zone substations Caulfield (**CFD**), Riversdale (**RD**), Armadale (**AR**) and East Malvern (**EM**) up to a maximum transfer capacity of 7.1MVA;
- install a new transformer at the adjacent zone substation East Malvern (**EM**) with three new distribution feeders to offload some of the load-at-risk at K zone substation at an estimated cost of $15.0 million; or
- install a third 20/33MVA transformer at K zone substation.

The least cost technically acceptable option is to install a new transformer at the EM zone substation and transfer the K load away. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR.

The use of contingency load transfers will mitigate the load-at-risk in the interim period.

7.2.11 Keysborough (KBH) zone substation

Keysborough (**KBH**) zone substation is served by sub-transmission lines from the Heatherton terminal station (**HTS**). It supplies the areas of Dandenong, Keysborough and Noble Park.

Currently, KBH zone substation consists of only one 20/33MVA 66/22kV transformer. United Energy commissioned KBH zone substation in 2014-15 to provide load relief for Dandenong South (**DSH**), Mordialloc (**MC**) and Noble Park (**NP**) zone substations, as well as to improve distribution feeder utilisation and supply reliability in these areas.

The actual maximum demand at KBH for summer 2024-25 was 29.87MVA. Being designated as a Metropolitan activity centre and a National employment and innovation cluster by the Victorian Government[10], the maximum demand in the Dandenong area is expected to continue to grow steadily over coming years. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26 there will be 31.2MVA of load-at-risk at KBH.

The (N-1) rating at KBH zone substation is zero because it is a single transformer zone substation. Therefore, customers' supply would be normally restored via the distribution feeder network from neighbouring zone substations, following the loss of the zone substation transformer or other fault resulting in the total loss of supply to KBH.

Whilst the probability of a transformer failure is low, the energy-at-risk resulting from a transformer fault is high, because customers supplied from this substation are exposed to such an event all year round.

To address the anticipated system limitation at KBH zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations Dandenong South (**DSH**), Dandenong (**DN**), Lyndale (**LD**) and Noble Park (**NP**) up to a maximum transfer capacity of 33.9MVA;
- install a second 20/33MVA transformer at KBH zone substation with two new distribution feeders at an estimated cost of $10.0 million;
- establish a new feeder from DSH and re-conductor 1.1km of feeder NP-14 in order to offload KBH. This option addresses only part of the energy-at-risk at KBH.

The least cost technically acceptable option is to install a new transformer at the KBH zone substation with two new distribution feeders. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.12 Langwarrin (LWN) zone substation

Langwarrin (**LWN**) zone substation is served by sub-transmission lines from the Frankston terminal station (**FTS**). It supplies the areas of Langwarrin, Botanic Ridge, Cranbourne South, and Skye. Currently, the LWN zone substation consists of two 20/33MVA 66/22kV transformers.

The actual maximum demand at LWN for summer 2024-25 was 45.93MVA. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26, there will be 3.9MVA of load-at-risk if there is a failure of one of the transformers at LWN. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system limitation at LWN zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Frankston (**FTN**) and Frankston South (**FSH**), up to a maximum transfer capacity of 26.6MVA;
- install a third 20/33MVA transformer at LWN zone substation with new distribution feeders at a cost of $10 million;
- establish a new Skye (**SKE**) zone substation with new distribution feeders at an estimated cost of $30 million.

The least cost technically acceptable option is to install a third transformer at LWN zone substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.13 Moorabbin (MR) zone substation

Moorabbin (**MR**) zone substation is served by sub-transmission lines from the Heatherton terminal station (**HTS**). It supplies the suburbs of Brighton, Hampton East, and Moorabbin. Currently, the MR zone substation consists of two 20/33MVA 66/11kV transformers.

The actual maximum demand at MR for summer 2024-25 was 49.05MVA. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26 there will be 11.6MVA of load-at-risk if there is a failure of one of the transformers at MR. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system limitation at MR zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load via the distribution feeder network to adjacent zone substations of Sandringham (**SR**), Bentleigh (**BT**), Ormond (**OR**) and North Brighton (**NB**) up to a maximum transfer capacity of 15.3MVA;
- install a third 20/33MVA transformer at MR zone substation for an estimated cost of $12.0 million.

The least cost technically acceptable option is to install a new transformer at the MR zone substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.14 Mornington (MTN) zone substation

Mornington (**MTN**) zone substation is served by sub-transmission lines from the Tyabb terminal station (**TBTS**). It supplies the areas of Merricks North, Moorooduc, and Mornington. Currently, the MTN zone substation consists of two 20/33MVA 66/22kV transformers.

The actual maximum demand at MTN for summer 2024-25 was 61.77MVA. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26, there will be 19.1MVA of load-at-risk if there is a failure of one of the transformers at MTN. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

To address the anticipated system limitation at MTN zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer away load via the distribution feeder network to adjacent zone substations of Dromana (**DMA**), Frankston South (**FSH**) and Hastings (**HGS**), up to a maximum transfer capacity of 20.6MVA;

- install a third 20/33MVA transformer at MTN zone substation at an estimated cost of $10.0 million.

The least cost technically acceptable option is to install a new transformer at the MTN zone substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.15 Ormond (OR) zone substation

Ormond (**OR**) zone substation is served by sub-transmission lines from the Malvern Terminal Station (**MTS**). It supplies the areas of Bentleigh East, Hughesdale, Murrumbeena, Ormond and parts of Oakleigh South.

Currently, the OR zone substation consists of two 20/27MVA 66/11kV transformers.

The actual maximum demand at OR for summer 2024-25 was 36.94MVA. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26 there will be 3.8MVA of load-at-risk if there is a failure of one of the transformers at OR. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers at OR zone substation. Consequently, an unplanned outage on one of the sub-transmission lines into OR would also result in an outage of one of the transformers at OR zone substation.

To address the anticipated system limitation at OR zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substations of Bentleigh (**BT**), Caulfield (**CFD**), East Malvern (**EM**) and Oakleigh East (**OE**) up to a maximum transfer capability of 9.46MVA;
- install a new transformer at the adjacent zone substation East Malvern (**EM**) with two new distribution feeders to offload some of the load-at-risk at OR zone substation at an estimated cost of $15.0 million; or
- install a third 20/33MVA transformer at OR zone substation at an estimated cost of $10.0 million.

The least cost technically acceptable option to address these limitations is to install a third 20/33MVA transformer at OR. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR

The contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.2.16 Sorrento (STO) zone substation

Sorrento (**STO**) zone substation is served by sub-transmission lines from the Tyabb terminal station (**TBTS**). It supplies the areas of Blairgowrie, Portsea, Rye and Sorrento.

Currently, STO zone substation consists of two 20/33MVA 66/22kV transformers.

The maximum demand at STO normally occurs during the Christmas and New Year holiday periods due to increased activities along the tip of the Mornington Peninsula. The actual maximum demand at STO for summer 2024-25 was 40.58MVA. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26 there will be 6.9MVA of load-at-risk if there is a failure of one of the transformers at STO. That is, it would not be able to supply all customers during high load periods following the loss of a transformer.

It is also noted that there are no 66kV sub-transmission line circuit breakers or 66kV bus-tie circuit breaker at STO zone substation. Consequently, an unplanned outage on one of the sub-transmission lines into STO would also result in an outage of one of the transformers at STO zone substation.

To address the anticipated system limitation at STO zone substation, United Energy considers that the following network solutions are technically feasible to manage the load-at-risk:

- contingency plans to transfer load away via the distribution feeder network to adjacent zone substation of Rosebud (**RBD**) up to a maximum transfer capacity of 13.3MVA; or
- install a third 20/33MVA transformer at STO zone substation at an estimated cost of $10.0 million.

The least cost technically acceptable option is to install a third transformer at the STO zone substation. However, given the economic cost of the limitation, this project is not expected to occur in the forward planning period for this DAPR. The contingency load transfers will be used to mitigate the load-at-risk in the interim period.

7.3 Proposed new zone substations

United Energy does not have any plans for new zone substations in the forecast period.

Table 7.2 Proposed new or redeveloped zone substations

Zone substation	Description	Direct cost estimate ($m)				
		2026	2027	2028	2029	2030
N/A						

8 Sub-transmission loops review

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

- Import limitations
  - forecasts for maximum demand to 2029-30; and
  - relevant seasonal N-1 ratings for each sub-transmission loop.
- Export limitations
  - forecasts for minimum demand to 2029-30; and
  - relevant N-1 export ratings for each sub-transmission loop.

Where the sub-transmission loop is forecast during 2025-26 to operate with 50% PoE maximum demand or 50% PoU minimum demand in breach of their firm import or export rating respectively, and the energy-at-risk is material, or if an augmentation project is planned, then this section assesses the energy-at-risk for those assets.

United Energy sets out possible options to address the system limitations. United Energy may employ the use of contingency load transfers to mitigate the system limitations although this will not always address the entire load-at-risk at times of maximum or minimum demand. At other times, the available transfers may be greater. As a result, the use of transfers under contingency situations may imply a short interruption of supply for customers or embedded generators to protect network elements from damage whilst all available load transfers take place.

Non-network providers may wish to review the limitations and consider whether alternative solutions (such as embedded generation, storage and demand management) to those augmentation plans set out in this chapter may be suitable. Solutions may also address zone substation limitations at the same time.

The annualised cost of the preferred network option provides a broad indication of the maximum potential value available to proponents of non-network solutions in deferring or avoiding network augmentation. However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation

United Energy notes that all other sub-transmission lines that are not specifically mentioned below either have maximum or minimum demand levels within the relevant rating, or the demand in breach of the relevant rating results in negligible energy-at-risk.

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

8.1 Sub-transmission loops with forecast limitations overview

Using the analysis undertaken below in Section 8.2, there is an investment need on one import-limited sub-transmission loop during the forward planning period for this DAPR. This is referred to as the Lower Mornington Peninsula project.

As part of this Lower Mornington Peninsula project, the proposed construction of a new 66kV sub-transmission line from Hastings (HGS) to Rosebud (RBD) zone substations is currently being deferred by a contracted non-network solution providing network support services. See Section 8.2.2 for further details. There are currently no identified import-limited sub-transmission line augmentations during the five-year forward planning period for this DAPR.

Whilst there is currently no proposed expenditure to address our sub-transmission line export limitations, United Energy is currently investigating a range of options in readiness for the expectation of future export limitations on our sub-transmission lines including:

- Reducing float voltages, or applying LDC settings at terminal stations;
- Installing reactors at terminal stations;
- Network reconfigurations and augmentations;
- Engaging with AusNet to review terminal station power transformer tap changer specification;
- Engaging with AEMO for opportunities to reduce transmission voltages at minimum demand;
- Engaging with AEMO to optimise existing capacitor bank switching controls at terminal stations; and
- Non-network options.

United Energy will continue to monitor the declining minimum demand levels on some of our sub-transmission lines and explore the feasibility of specific options to alleviate any forecast export limitations, on a case-by-case basis.

The options and analysis are presented in the sections below.

8.2 Sub-transmission lines with forecast system limitations

8.2.1 HTS-MR-BT-NB-HTS

The HTS-MR-BT-NB-HTS 66kV sub-transmission loop supplies Moorabbin (MR), Bentleigh (BT) and North Brighton (NB) zone substations from Heatherton terminal station (HTS), at 66kV.

The actual maximum demand on the HTS-MR-BT-NB-HTS sub-transmission system for summer 2024-25 was 144MVA.

The maximum demand is expected to exceed its summer (N-1) rating over the forward planning period for this DAPR. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26, there will be 15MVA of load-at-risk in the event of the worst-case outage of a sub-transmission line within the loop system during high load periods. Load-at-risk could arise:

- predominantly on the HTS-NB sub-transmission line for an outage of the BT-MR sub-transmission line;

To address the anticipated system limitations within this sub-transmission line system, United Energy considers the following network options are technically feasible to manage the load-at-risk:

- maintain contingency plans to transfer load to adjacent sub-transmission systems and the use of dynamic line ratings. Transfer capability away from this system is assessed at 11.3MVA for summer 2025-26;
- thermally up-rate approximately 4 km of the HTS-NB sub-transmission line at an estimated cost of $6 million

Given the forecasted annual hours at risk is low, this project is not expected to occur in the forward planning period for this DAPR. The use of the contingency plans will be used to mitigate the load-at-risk in the interim period.

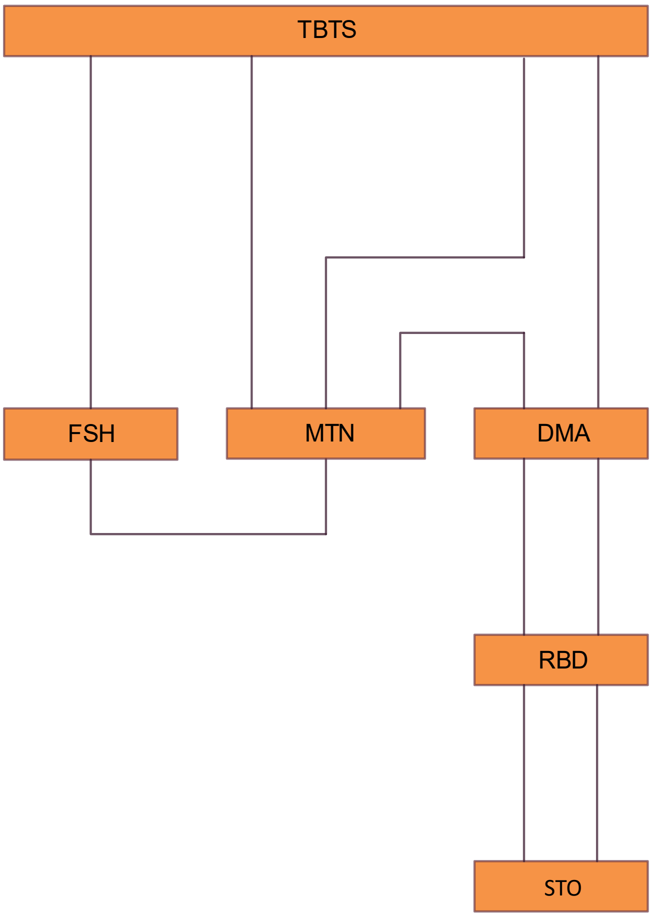
8.2.2 TBTS-FSH-MTN-DMA-TBTS

The TBTS-FSH-MTN-DMA-TBTS sub-transmission system supplies the Frankston South (**FSH**), Mornington (**MTN**) and Dromana (**DMA**) zone substations from Tyabb terminal station (**TBTS**) at 66kV. Rosebud (**RBD**) and Sorrento (**STO**) zone substations are connected to DMA as a secondary system and are supplied through the TBTS-DMA-MTN sub-transmission system as shown below.

Given the multiple supply routes and voltage limitations in this system, the risk assessment for this system is more complicated compared with other sub-transmission systems. Therefore, load flow results are used to undertake the risk assessment. The analysis is broken down as follows:

- TBTS-DMA-MTN system capacity limitation;
- DMA-RBD-DMA system capacity limitation; and
- voltage collapse limitation in the lower Mornington Peninsula.

Figure 8.1 TBTS-FSH-MTN-DMA-TBTS sub-transmission system



TBTS-DMA-MTN

This is a subset of the main TBTS-FSH-MTN-DMA-TBTS sub-transmission system. The actual maximum demand on the TBTS-DMA-MTN sub-transmission system for summer 2023-24 was 90MVA. The maximum demand is expected to exceed its summer (N-1) rating over the forward planning period for this DAPR. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26, there will be 28.5MVA of load-at-risk in the event of the worst case outage of a sub-transmission line within the loop system during high load periods. Load-at-risk could arise on the TBTS-DMA sub-transmission line for an outage of the MTN-DMA sub-transmission line, or vice versa.

DMA-RBD-DMA

The DMA-RBD-DMA sub-transmission system supplies Rosebud (**RBD**) zone substation from Dromana (DMA) zone substation, at 66kV. The line from RBD to Sorrento (**STO**) zone substation is separately assessed and currently has no energy-at-risk.

The actual maximum demand on the DMA-RBD-DMA sub-transmission system for summer 2024-25 was 79MVA. The maximum demand is expected to exceed its summer (N-1) rating over the forward planning period for this DAPR. For more details, please refer to the Max and Min Demand Template.

United Energy estimates that in the summer of 2025-26, there will be 22MVA of load-at-risk in the event of the worst case outage of a sub-transmission line within the loop system during high load periods. Load-at-risk could arise on the DMA-RBD No.1 sub-transmission line for an outage of the DMA-RBD No.2 sub-transmission line, or vice versa.

Voltage collapse

United Energy has also identified a risk of voltage collapse in the lower part of the Mornington Peninsula should an unplanned outage of either the MTN-DMA or the TBTS-DMA sub-transmission line occur during maximum demand periods, with the former being the more severe condition. Given the relatively long sub-transmission lines extending to STO from TBTS (approximately 59km), the voltage collapse limitation is considered to be more prominent over the thermal capacity limitation.

United Energy already has installed capacitor banks at STO and RBD zone substations to provide reactive power compensation for the load. Although DMA zone substation is not equipped with any capacitor banks, the station also operates near unity power factor due to the use of pole-mounted capacitor banks within the 22kV distribution network.

The effectiveness of these devices, together with the on-load tap changers (of zone substation transformers) to maintain voltage levels within acceptable levels, is diminishing rapidly in the event of loss of one of the upstream sub-transmission lines to DMA zone substation during maximum demand conditions because of the magnitude of the losses along the sub-transmission lines.

United Energy has identified that a DMA-RBD-STO load of 123MW or greater, together with an unplanned outage of the MTN-DMA sub-transmission line, will likely cause voltage collapse of the loop. To manage this risk, United Energy has 10MW of demand management capability available. If the load is expected to exceed the 123MW threshold after these combined mitigation measures, pre-contingent load shedding would be required to maintain system security. While some level of load transfer may be available on the distribution network to manage thermal constraints, the speed with which the voltage collapse event occurs prevents the post-contingent use.

Overall assessment

In May 2016, United Energy published a Final Project Assessment Report (**FPAR**) for the Lower Mornington Peninsula, which was the final stage in the Regulatory Investment Test for Distribution (**RIT-D**) process. The RIT-D assessment recommended a technically feasible and economic solution, which is a combination of network and non-network options, to mitigate the system limitations in the Mornington Peninsula sub-transmission network. United Energy has committed to this solution and the demand management program has been in service since summer 2018-19. Presently, the program consists of:

- 9MW of emergency generation; and
- 1MW of battery energy storage system (BESS)

Recent market testing and economic analysis demonstrated that continuing the demand management solution until the construction of the new 66kV line (expected to be completed before FY2030/31) is the most efficient solution. United Energy will continue to monitor the load growth and explore technically viable non-network solutions in the area to complement the existing demand management program.

The total cost of the solution is estimated at $5.6M across the next 6 years. This non-network solution:

- reduces energy-at-risk in the lower Mornington supply area;
- defers the network augmentation by 5 years;
- maximise net economic benefits for the electricity market;
- address capacity limitation on the DMA-RBD sub-transmission lines;
- address capacity limitation on the MTN-DMA sub-transmission line;
- address capacity limitation on the TBTS-DMA sub-transmission line; and
- address voltage collapse limitation in the lower Mornington Peninsula.

8.3 Proposed new sub-transmission lines

This section sets out United Energy's plans for new sub-transmission lines. These lines are not considered in the forecasts that have been set out in the Max and Min Demand Template as that only relates to existing sub-transmission lines.

The table below provides an overview of the sub-transmission lines that United Energy is proposing to build during the forward planning period for this DAPR to address future loading levels.

Table 8.1 Proposed new sub-transmission lines

Name	Location	Proposed commissioning date	Reason
HGS-RBD	Hastings to Rosebud	June 2031	Demand and voltage limitations in the lower Mornington Peninsula area.

8.3.1 New HGS–RBD sub-transmission line

In order to alleviate the capacity and voltage collapse conditions in the lower Mornington Peninsula, UE plans to establish a new HGS-RBD 66 kV line in 2031 at an estimated cost of $38.0 million. As part of this project, the existing TBTS-HGS 66 kV lines are likely to require upgrading at the same time due to the additional load imposed on this system.

9 Transmission-distribution connection point reviews

United Energy undertake undertakes forecasting and assessment of transmission–distribution connection points in accordance with the requirements of the National Electricity Rules (NER). Forecasts of both import and export capability, along with any associated limitations at terminal stations, are documented in the Transmission Connection Planning Report (TCPR). Please refer to the TCPR for further details.

10 Primary distribution feeder reviews

Where practicable, United Energy has prepared maximum and minimum demand forecasts for primary distribution feeders over the forward planning period for this DAPR that assesses the balance between capacity and demand. This chapter discusses the primary distribution feeders that have demand levels that are:

- currently in breach of their import or export ratings; or
- forecast to be in breach of their import or export ratings.

Under United Energy's probabilistic planning, distribution feeders are generally loaded to greater than 85 percent maximum demand utilisation of their import rating before they are considered for possible augmentation eligibility, as this represents a typical trigger-point at which feeder augmentations may become economic. The transfer capabilities reserved for maintaining continuous supply to our customers during emergency conditions diminishes with increased distribution feeder utilisation. For minimum demand, the threshold applied is 100 percent minimum demand utilisation of their export rating.

We invite non-network providers to review the limitations and consider whether alternative solutions (such as embedded generation, storage and demand management) to those set out in the analysis may be suitable. United Energy anticipates an increasing number of non-network options will emerge over the next few years, particularly for distribution feeder and low-voltage limitations, as the market and technology develops and matures.

10.1 Overview of primary distribution feeders with forecast overload

The table below provides information regarding critical distribution feeder import limitations where network augmentation to alleviate those limitations are likely to be economic and are currently planned within the next two years.

A number of options are considered in identifying suitable mitigation measures to alleviate thermal capacity and transfer capacity issues on distribution feeders, including:

- permanent load transfers to neighbouring feeders,
- feeder reconductoring,
- thermal uprate,
- reactive power compensation,
- new feeder ties or extensions,
- new feeders,
- non-network alternatives.

The most appropriate option is selected based on practical feasibility and least lifecycle cost.

Table 10.1 Distribution feeder import limitations

Feeder/ Voltage	Feeder location	Import Rating (MVA)	Forecast utilisation (%)				
			2025/26	2026/27	2027/28	2028/29	2029/30
DVY 24 (22kV)	Dandenong South, Lyndhurst, Bangholme, Carrum Downs	11.6	99%	113%	131%	133%	132%

The table below provides information regarding critical distribution feeder export limitations where network augmentation to alleviate those limitations are likely to be economic and are currently planned within the next two years.

A number of options are considered in identifying suitable mitigation measures to alleviate generation export issues on primary distribution feeders, including:

- tuning our DVMS at that zone substation;
- in-line feeder HV voltage regulators;
- network reconfigurations or augmentations to shorten feeders or split feeders;
- optimisation of capacitor bank switching settings on existing in-line feeder shunt capacitor banks; and
- non-network options.

The most appropriate option is selected based on practical feasibility and least lifecycle cost.

Table 10.2 Distribution feeder export limitations

Feeder/ Voltage	Feeder location	Import Rating (MVA)	Forecast utilisation (%)				
			2025/26	2026/27	2027/28	2028/29	2029/30
	Nil						

The section below identifies the amount of load or generation reduction that would be required to defer the proposed augmentations by one year.[11] It also identifies the least cost technically appropriate solution that would be undertaken in the absence of any commitment from interested parties to offer network support services through demand side management initiatives.

There are currently no forecast export limitations and consequently no planned augmentation to alleviate feeder export limitations within the next two years.

[11] This is an indicative figure only. The amount of load reduction required to defer the proposed augmentations will be finalised via a detailed risk assessment / business case.

10.2 Primary distribution feeders with forecast overload

10.2.1 DVY 24 feeder

DVY24 provides electricity supply to a fast growing industrial and commercial customer base in Dandenong South. It is supplied from the Dandenong Valley zone substation (DVY). It is a high-capacity feeder with a thermal capacity of 11.6 MVA

Dandenong South's growth is driven by large greenfield developments, particularly in the area south of Abbots Road and East of Dandenong-Frankston Road. There is substantial amount of undeveloped land available in the area with easy access to major arterial roads.

Without intervention, demand growth is expected to exceed the capacity of DVY24 in 2026/27. Operational transfers are available to reduce the energy at risk resulting from exceedance of DVY24's capacity, but a longer-term solution is necessary to mitigate energy at risk.

Without intervention, exceeding the thermal capacity rating of DVY24 will result in deteriorating reliability of supply.

Several credible options were considered to address this constraint. The preferred option is to establish a new feeder at DVY to offload DVY24 at a cost of $1.3mil.

Assessment of optimum project delivery timing found that the economic benefits of option two are maximised if it is no later than 2026/27.

11 Joint Planning

This chapter sets out the joint planning with DNSPs and TNSPs in relation to zone substations and sub-transmission lines, outlining the process and methodology used for joint planning, including any planned investments, estimated capital costs and timelines.

United Energy has not identified any new required projects from our joint planning activities with other DNSPs in 2025. Our previous joint planning activities have included sharing load forecast information and load flow analysis between Victorian distributors relating to the sub-transmission system. Where a constraint is identified on our network that may impact another distributor, then project specific joint planning meetings are held to determine the most efficient and effective investment strategy to address the system constraint.

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

12 Changes to analysis since last year

12.1 Timing of proposed network augmentations

The network limitation assessment and timing of network augmentations presented in this DAPR are based on United Energy's 2025 maximum demand forecast and the escalated AER VCR estimates. The timing is also based on the annualised cost of the network augmentation option.

While subdued maximum demand growth is expected for the overall United Energy network, there remain pockets of strong growth which typically occur in the parts of our network that are currently operating well above the average utilisation. The timing of our network augmentations has been determined on a case-by-case basis and may change over time as options are re-evaluated.

Table 12.1 below summarises the timing of proposed major network augmentations.

Table 12.1 Changes in timing of proposed major network projects

Proposed Major Project	2025 DAPR	2024 DAPR
N/A		

12.2 Timing of proposed asset retirements / replacements and deratings

United Energy is also required to detail information on its asset retirements / replacement projects and deratings in its DAPR as described in Chapter 15. The timing of these may change subject to updated asset information, portfolio optimisation and realignment with other network projects, or reprioritisation of options to mitigate the deteriorating condition of the assets.

United Energy has made minor adjustments to the risk quantification for these locations. These changes primarily involve refinement of estimated failure probabilities for assets, as well as updated consequence values to incorporate additional data captured in 2025. The timing was also updated for the latest maximum demand forecast and VCRs as detailed above. The assessment of load-at-risk includes existing risk management controls (such as available load transfers, relocatable transformer readiness and switchgear spares holdings) where applicable. As a result, some asset retirements have been deferred, and other future retirements have been brought forward.

Table 12.2 below summarises the change in timing of proposed major network retirements/replacements and deratings.

The main changes in timing relate to costs, asset condition and site risk assessments, reduced energy at risk, and demand growth forecasts.

Table 12.2 Changes in timing of asset retirements / replacements and deratings

Proposed Asset Replacement	2025 DAPR	2024 DAPR
Hastings (**HGS**) 22 kV Switchyard replacement	Not included	2026

13 Asset management

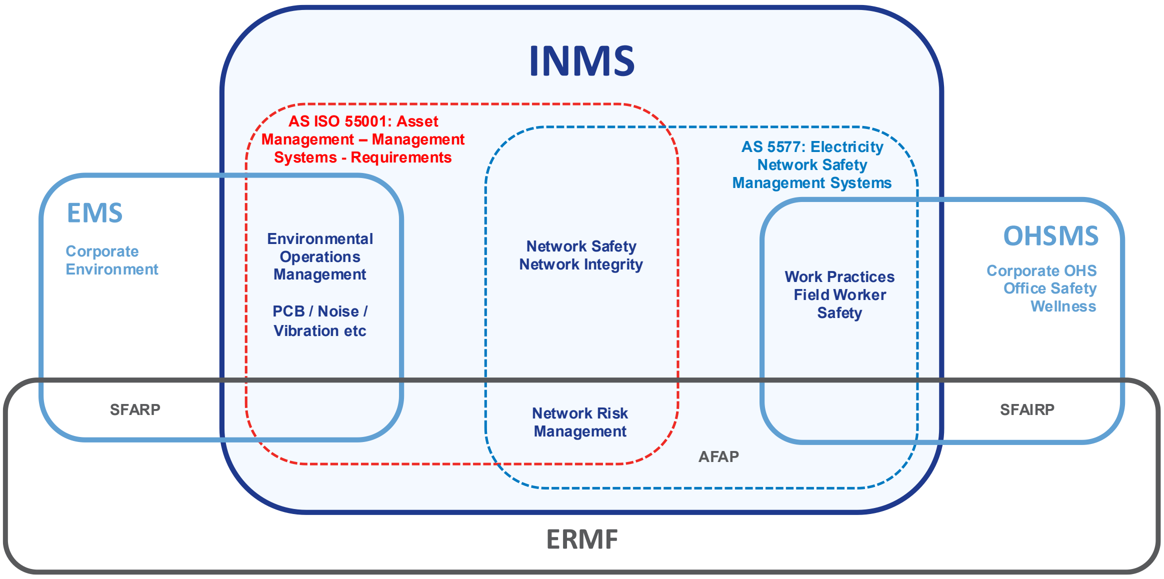
This chapter details the United Energy Asset Management System (**AMS**), that forms part of the Integrated Network Management System (**INMS**).

13.1 Integrated Network Management System (INMS)

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

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

Figure 13.1 Scope of the integrated network management system



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

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

These management system standards are aligned with the UE certification for management system standards:

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

and the business' Enterprise Risk Management Framework (13-10-CPPCUE0005) which is based on the principles outlined in the AS/NZS ISO 31000:2018 Risk Management – Guidelines.

The INMS which is currently with ESV for acceptance, complies with the Electricity Safety (Management) Regulations 2019, and will replace the existing accepted United Energy Electricity Safety Management Scheme (UE-ST-2921) document. The scope of the INMS does not include the legislative obligations, non-electrical risks, nor risks associated with:

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

The INMS, and associated management system standards, that facilitates the effective and efficient delivery of the INMS objectives, and:

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

13.2 Asset management system

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

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

13.3 Asset management policy principles

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

- Minimise safety risks as far as practicable.
- Provide safe, affordable (least long-term cost) and reliable network services, taking into consideration customer values and needs.
- Apply a risk-based approach to optimise the management and development of our network and systems.
- Build network resilience, including to the impacts of climate change.
- Engage and listen to our customers and communities to incorporate their input into decisions and adapt to their interests and needs.
- Invest in programs that sustainably optimise the total lifecycle management of our network.
- Comply with all relevant legislative and regulatory requirements as well as Australian and industry standards and any other requirements to which we subscribe.
- Enable employees with the right skills and capabilities so they can be the best they can be.
- Monitor and evaluate appropriate metrics to effectively manage the network and customer service performance.
- Continuously improve our management systems and activities by embracing innovation and technology to enhance our reputation, leading the industry in adopting and promoting network management practices where it makes sense to do so.
- Facilitate the energy transition to ensure system security requirements are achieved.

13.4 Asset management strategies, and objectives

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

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

- manage and operate the network safely
- meet our network reliability performance targets
- manage our assets on a least cost total life cycle basis
- adapt to our customer’s future needs
- manage our compliance obligations
- empower and invest in our employees

- monitor opportunities and drive continuous improvement.

13.5 Asset class management plans

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

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

13.6 Capex / Opex Works Program (COWP)

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

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

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

1. Customer requirements: customer expectations and current performance.
2. Economic requirements: projects are subject to a level of economic analysis in accordance with regulatory requirements and prudent investment tests.
3. Technical requirements: inputs that drive the network requirements, including:
    - Network performance: asset maintenance and replacement programs: driven by an analysis of fault/performance/cost data, based on reliability centred maintenance analysis.

  - Safety compliance: INMS, and the Electricity safety legislation, detail the risk-based approach to managing electrical safety.
  - Capacity planning: probabilistic analysis and contingency planning
  - Risk analysis: ERMF, and ISO 31000 for significant asset risks

13.7 System limitations identified through asset management

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

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

13.8 Contact for further information

Further information on the United Energy asset management strategy and methodology may be obtained by contacting planning@ue.com.au. Detailed enquiries should be forwarded to the appropriate United Energy representative.

14 Asset management methodology

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

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

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

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

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

14.1 Distribution assets

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

- Measurement of the sound wood: poles
- Dissolved Gas Analysis (**DGA**) and oil quality assessment of transformers
- Partial Discharge (**PD**): HV/MV cables
- Thermography
- Monitoring of insulation levels (gas/oil)
- Asset performance history

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

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

- More frequent condition assessment or inspection
- Asset reinforcement, such as pole staking
- Asset de-rating or retirement
- Overhaul / refurbishment
- Non-network solutions
- Asset replacement.

14.2 Zone substation assets

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

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

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

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

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

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

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

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

The asset replacement outlined in Chapter 15 is a forecast based on the historic number of asset replacements (typical number for high volume assets such as poles) and based on an assessment of the currently available condition data for specific assets. Chapter 15 includes methodologies used for the replacement of each asset class.

15 Asset retirements and deratings

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

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

The accompanying System Limitations Template details a number of asset retirements and de-ratings that result in a system limitation.

All planned network retirements or planned asset de-ratings that would result in a system limitation, are described individually below. Where more than one asset of the same type is to be retired or de-rated in the same calendar year, and the capital cost to replace each asset is less than $300,000, then the assets are reported together below.

A summary of the individual assets that are planned to be retired/replaced is provided in the table below.

Table 15.1 Planned asset replacements

Location	Asset	Project	Retirement date
Elwood (**EW**) zone substation	Elwood (**EW**) 11kV Switchboard and Relays	Replacement	2027
Elwood (**EW**) zone substation	Elwood (**EW**) #2 Transformer	Replacement	2028

This chapter also sets out the committed investments to be carried out during the forward planning period for this DAPR worth $3 million or more to address urgent and unforeseen network issues.

15.1 Individual asset retirements / replacements

This section discusses planned network retirements, or planned asset de-ratings that would result in a system limitation. For more details and data on these limitations please refer to the attached System Limitations Template. Note that the System Limitation Template includes a high-level risk assessment only. A more detailed and accurate assessment will be carried out at the business case or Regulatory Investment Test for Distribution (**RIT-D**) stage if the project cost exceeds $7 million.

15.1.1 Transformer retirements / replacements

Zone substation transformers are critical elements in the distribution network because of their high replacement cost, their strategic impact on customer supply and their long lead time for repair or replacement. An in-service failure will result in significant energy limitations for around 6 months.

The replacement of these assets is driven by multiple condition assessments of the insulating system, including oil, paper and mechanical withstand capability. An analysis of condition and risk is conducted for all transformers on an individual basis to determine a prudent program of proactive replacement.

Elwood (EW) #2 Transformer Retirement/Replacement

Elwood (EW) zone substation supplies the beachside suburbs of Elwood, parts of St Kilda and Elsternwick. The zone substation is a fully indoor type, which comprises two identical 20/27MVA transformers operating at 66/11kV that were commissioned during the 1960s.

The existing EW transformers (#1 and #2) are over 50 years old and their condition is assessed as being very close to end of life. The #2 transformer at EW is in the poorest condition, based on several condition assessments. Based on the condition and risk assessments conducted the #2 transformer is end of life and is economically justified for retirement and replacement by the end of 2028.

The retirement would lead to a significant amount of load-at-risk, with up to 26MVA of lost load in winter 2028, in the event of a failure of the remaining transformer.

To address the anticipated system limitation at EW zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- contingency plans also exist to transfer load via the distribution feeder network to adjacent zone substations Elsternwick (**EL**) and North Brighton (**NB**) up to a maximum transfer capacity of 3.0MVA;
- replace #2 transformer in 2028 at an estimated cost of $4.6 million. The #1 transformer will be assessed for replacement in the future however, with the replacement of the #2 transformer, it is not expected to be economic within the 5 year planning period;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of transformer failures. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 4.1MW.

The least cost technically acceptable option is to replace the #2 transformer at EW in 2028. In accordance with United Energy’s economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution when compared with the other network options outlined above. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

15.1.2 Switchgear retirements / replacements

Switchboards are critical infrastructure for the safe operation of a zone-substation. A switchboard allows the transfer of power from the zone-substation transformers through to the distribution feeders. They also provide the electrical protection for the transformer and each distribution feeder.

A switchboard has many failure modes that will lead to different levels of customer impact. The complete failure of a switchboard could lead to its associated feeders and associated power transformer being out of service for between 4 to 8 months while it is being repaired or replaced.

Elwood (EW) 11kV Switchboard and Relay Replacement

The assets at the EW zone substation are approaching the end of their life. The existing oil-filled metal-clad switchgear is approaching 60 years old and is experiencing a decrease in reliability and condition.

This combination of decreasing condition, along with the supply impacts to customer reliability and energy supply capability indicate that the switchboard is forecast to be no longer economically prudent to operate beyond 2027. In summer 2025/26, we forecast up to 14.3MVA of load is at risk in the event of a circuit breaker failure at EW. To address the anticipated system limitation at EW zone substation, United Energy considers that the following network solutions are technically feasible to manage the risk:

- continuing to operate the station as-is. In the event of a switchboard failure, this would result in significant load-at-risk for between 4 to 8 months until the switchgear can be repaired or replaced. Contingency plans also exist to transfer load via the distribution feeder network to adjacent zone substations Elsternwick (**EL**) and North Brighton (**NB**) up to a maximum transfer capacity of 3.0MVA;
- replace the switchboard and relays in 2027 at an estimated cost of $5.7 million;
- defer proactive replacement by contracting a demand management solution to reduce the load-at-risk in the event of a switchgear failure. To potentially defer the project the solution would need to reduce the station maximum demand by approximately 5MW in the event of a failure of a bus at EW.

The least cost technically acceptable option is to replace the 11kV switchboard at EW in 2027. In accordance with United Energy's economic assessment framework, this is demonstrated to be the least-cost technically acceptable network solution that addresses all risks associated with the switchgear when compared with the other network options outlined above. The use of contingency load transfers will be used to mitigate the load-at-risk in the interim period.

15.2 Grouped asset retirements / replacements

This section discusses planned replacements for groups of assets. For more detail on United Energy's asset management methodologies please refer to Chapters 13 and 14.

15.2.1 Poles

Poles are located throughout the United Energy territory and replaced each year at various locations and timing depending upon asset condition. The location and timing of the asset replacement are not known before inspection. United Energy expects to replace a large number of poles during the forward planning period for this DAPR.

Routine inspection and rectification work maintains the general condition of all pole populations in a serviceable condition.

Pole replacement and reinstatement occurs as a result of a cyclic condition inspection that involves inspection and testing of poles to ensure that they are fit for purpose. The assessment criteria classifies poles as serviceable, limited life or unserviceable.

15.2.2 Pole top structures

Pole top structures consist of cross-arms, insulators, stay wires and associated hardware.

The wooden cross-arm population is aged and consequently the risk of asset failure and pole fires is increasing.

The condition of pole top structures and cross-arms is monitored as part of the routine asset inspection and replacement occurs based on condition. The location and the timing of the asset replacements are not known before inspection. United Energy expects to replace a large number of pole top structure assets during the forward planning period for this DAPR.

15.2.3 HV fuses

HV Outdoor Fuses consist of Boric Acid (**BA**), Expulsion Drop Out (**EDO**) and Powder Filled (**PF**) type fuses. The HV fuses are located through-out the United Energy overhead electrical distribution system. HV outdoor fuses are sacrificial devices used to provide overcurrent protection to downstream circuits and assets by interrupting high fault currents.

HV Fuses are currently performing at an acceptable level. Their condition is assessed as part of routine pole top asset inspection. The main drivers for replacement of HV fuse holders are:

- damage identified as part of asset inspection,
- in-service failure,
- unacceptable EDO fuse type,
- EDO replacement due to high fault-levels.

The location and the timing of the asset replacements are not known before the inspection. Once identified, replacement of HV fuses may be proactive, depending on assessed condition and risk.

15.2.4 Pole mounted HV line capacitors

Line capacitors are assets that are located on HV feeders attached to poles and consist of three single-phase capacitor cans and three single-phase switches. The switches control the connection to the distribution network, via a manual or automated switch, to manage power factor and voltage levels on local areas of the network. These are located throughout the distribution network.

The main deterioration drivers for line capacitors are:

- accumulated electrical stress causing degradation and insulation failure of capacitor cans;

- exposure to network harmonics results is accelerated aging of capacitors cans;
- degradation of control box housing, resulting in failure of the control box and the capacitor bank failing to operate correctly, remaining either switched in or out;
- accumulated switching operations deteriorates HV switches due to high in rush currents and may lead to switch failure; and
- damage from lightning strikes.

The condition of line capacitors is assessed as part of:

- the 3/5 year inspection of overhead assets;
- detailed pre-summer checks of all fixed capacitors; and
- switched capacitors (controlled by time, temperature or VAR) are checked remotely by using the information system PI. The system will look for step changes in feeder reactive power when the capacitors are switched.

Replacement drivers for line capacitors are based on in service failures or replacements due to condition or defects as identified by inspection, as well as considering the distribution power factor levels at the substation. Location and the timing of the asset replacement are not known until the inspection.

15.2.5 Overhead conductor

United Energy has approximately 10,034 route km of overhead line, the large majority of which is bare conductors. Lines were initially hard drawn stranded copper or galvanized steel which now represents the oldest conductors in the overhead network. Steel Reinforced Aluminium Conductor (**ACSR**) was introduced in about 1960 followed by "All Aluminium" Conductor (**AAC**) in about 1975. Stranded Aluminium conductor now represents the predominant conductor in the network.

Aerial Bundled Cable (**ABC**) was introduced in the late 1980s and this is the current overhead line standard for new and replacement LV lines.

High-voltage ABC and covered conductor has been used in special applications for managing fire risk and protecting trees of significant community value. United Energy expects to replace a large number of kilometres of overhead lines with insulated solutions during the forward planning period for this DAPR.

Overhead conductor condition is assessed as part of routine overhead asset inspection including use of elevated camera inspections. Replacement of conductor where poor performance is identified is based on results of elevated camera inspections or investigation of condition and tensile strength of in-service samples. The location and the timing of the asset replacement are not known until the time of the inspection.

The condition of existing copper and aluminium conductors is generally considered to be good. For the majority of the network there are no planned replacements considered necessary. The conductor that is replaced is identified via inspection or other condition monitoring to be in poor condition, requiring prompt replacement to address the risk of failure. The required replacement timeframe from detection of the defect to replacement is between 3 to 6 months.

The performance of existing ampact connectors is deteriorating. United Energy has a strategy to replace a portion of these connectors over a 5-year time period. The replacements will occur through targeted proactive risk-based replacement programs in conjunction with replacements due to faults.

15.2.6 Underground cables

The majority of underground cables on the United Energy network consist of cross-linked polyethylene (**XLPE**). XLPE cables have a generally good performance. Most of the issues are in the earliest vintage single core single jacket cables from the former Doncaster and Templestowe Council. These are up to 37 years of age and are suffering from water treeing related insulation failure. Elsewhere most cable failures are in joints on cables of early manufacture. The 66kV cables are not posing any issues.

Replacement decisions on underground cables are based on condition assessment, fault history and economic evaluation. It is expected that the majority of underground cable replacement will occur in the Doncaster and Templestowe region of United Energy during the forward planning period for this DAPR, however the timing of these replacements is not known at present. Volumes of cable replacements are expected to continue to increase in the forward planning period for LV and HV cables.

15.2.7 Low-voltage services

Services are network assets that connect a customer, from their residence to the electricity network. They can be overhead conductors or underground cables and supply all residential, industrial and commercial customers.

There are various types of services on the network reflecting a broad time span. They include:

- Neutral Screen (aluminium & copper);
- PVC grey twisted;
- XLPE black;
- other.

The condition of LV services is assessed as part of:

- the 3/5 year inspection of overhead assets;
- monitoring of neutral integrity through smart meters;
- Neutral & Supply Testing (**NST**) of non-smart meter premises.

The performance of neutral screened services has deteriorated with age and resulted in a relatively high number of electric shock incidents, commonly due to a broken or high impedance neutral connection.

Replacement drivers for LV services include:

- replace on failure or as identified to be faulty after inspection;
- replacement due to high neutral resistance as determined by smart meter or NST test;
- replacement of neutral screen services at sites without a smart meter;
- replacement as a result of service not meeting minimum required ground clearance;
- often a service breakaway device is installed on a low service or a service with a potential tree hazard;
- replacement due to property crossing issues; and
- 10-year proactive replacement program for specific service types (i.e., neutral screens and twisted pairs) based on the heightened risk profile.

United Energy's policy is that any non-preferred service cable encountered during maintenance works is replaced. Specifically, this includes Twisted Pair, Neutral Screen Services and any services that do not conform to current height standards. Currently all services other than ABC services are considered to be "non-preferred" and will be opportunistically replaced with the current standard, when undertaking other LV planned works on a pole, or based on inspection or condition assessment.

Location and the timing of the asset replacement are not known until the inspection or condition assessment. United Energy expects that it will replace a large number of services during the forward planning period for this DAPR.

15.2.8 Distribution transformers

Distribution substations are categorized as indoor, kiosk, ground mounted (compound) or pole mounted type substations. They are supplied via the High-Voltage distribution network from zone substations.

Distribution substations are comprised of high-voltage switchgear and associated protection equipment (high-voltage fuses or protection relays controlling high-voltage circuit breakers), a transformer or transformers, and low-voltage switchgear and associated protection equipment (generally fuses but can include low-voltage circuit breakers). It includes an earthing system and is constructed to ensure unauthorised access to the equipment by the general public is prevented.

The condition of distribution substations is monitored via visual inspection and thermal (infra-red) scanning. This is carried out on a routine basis. Pole top substations are inspected as part of the pole and line inspection program. Indoor and kiosk substations are inspected as part of a separate program aimed at ensuring the condition and security of these installations is maintained and the grounds and easements, they are installed in are maintained in good condition.

Defects identified in these inspections are to be repaired in a timeframe commensurate with the severity of the defect or with the scheduled switchgear preventive maintenance where applicable or scheduled for later repair in logical work packages to minimise the number of times customers are off supply.

There is no programmed replacement of substations as a whole. Replacement is triggered generally by load increase, failure, regulatory requirements or condition assessment.

Distribution transformers have a long life expectancy, and, except when replaced for increased load reasons are normally run to failure. Nevertheless, a small number, are replaced each year for various reasons including minor oil leaks and internal winding failure. The location and the timing of these replacements are not known until condition inspection or monitoring.

15.2.9 Distribution switchgear

Overhead switchgear

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

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

Overhead switchgear is inspected for condition and to identify defects as part of routine 3/5 year overhead asset inspection. Thermal survey of ACRs is undertaken as part of the regular distribution overhead feeder thermal surveys. ACRs undergo 4-yearly maintenance alternating minor and major maintenance. Major maintenance involves functional testing, battery replacement and verification of protection time-current characteristics and general cleaning and tightening of components while minor maintenance only involves battery replacement and general cleaning.

ABS ceased to be installed on network in approximately 1994 and since then gas insulated switches are the standard. These switches are demonstrating an increasing rate of functional failure as a percentage of the population, indicating that their condition is deteriorating. Maintenance on these switches has proved ineffective as switch misalignment and maloperation persist. As a result of their ineffective operation and potential health and safety issues posed to operators there is a reluctance to use these switches.

To address the ABS issues, United Energy strategy has been to proactively replace all ABS with gas-insulated switches. Switches are replaced as part of proactive programs and on failure. The location of replaced switches will be randomly distributed throughout the United Energy network.

Gas switches are replaced due to defect or failure. Increased volumes of ILJIN type gas switches are to be replaced over the planning period due to accelerated deteriorating impacting on normal operation of the network.

LV switchgear installed on the overhead network comprises the two main groups i.e., LV open blade isolators or LV fused/switch disconnectors housed in an insulated enclosure. The condition of these switches is routinely determined as part of asset inspection and replacement scheduled based on condition.

LV switches are simple devices and do not have many working parts or maintainable/replaceable elements. It is not possible or cost effective to replace individual components or to undertake maintenance of these assets. Therefore, these assets are currently replaced when identified to be defective.

There is an increasing number of LV switches that have reached or exceeded their expected life. This has been experienced on the network as an increase in the number of LV switch replacements.

Ground Mounted Switchgear

Ground mounted switchgear is mostly a component of non-pole distribution substations but may also be standalone switchgear. HV switchgear provides load switching functionality plus transformer protection. There has been an array of switchgear on the network ranging from physically separated air-break gear with limited switching capacity through to fully integrated gas insulated switches with full network load-break/fault-make capabilities. The number and types of switching technology used has been progressively rationalised.

The condition of switchgear is assessed as part of routine six monthly asset inspections and where required corrective maintenance or replacement undertaken. The location and the timing of the asset replacement is not known until the inspection.

Modern current standard switchgear comprises gas-insulated ring main units (**RMU**). These are of varying ages with the oldest units up to 35 years old. The performance is in general considered satisfactory and no preventative maintenance is undertaken.

There are also varying non-preferred switchgear employing older air-break technology or having reliability issues and no longer supported by the manufacturer with spares. Non-preferred switchgear (particularly the indoor wall mounted air-break type) suffer from misalignment and maintenance is ineffective. Due to this and the potential H&S issues they are seldom used.

United Energy has a strategy to replace all non-preferred switchgear with modern gas insulated RMU technology over a 10-year period. The replacements will occur through targeted proactive programs in conjunction with replacements due to faults.

15.2.10 Surge arresters

Surge arresters are located throughout the United Energy overhead electrical distribution system. Surge arresters are a sacrificial protective device. Their function is to protect other valuable assets from the high-voltage spikes, such as those caused by lightning and switching surges. The location and the timing of the replacement are therefore not known in advance.

There is no corrective or preventative maintenance undertaken and surge arresters are run to failure.

The main drivers for replacement of surge arresters are:

- replace on failure or as identified to be faulty after inspection;
- targeted replacement of non-preferred surge arresters; and
- bulk replacement as part of any Rapid Earth Fault Current Limiter (**REFCL**) projects of surge arresters that do not meet the required overvoltage duty.

15.2.11 66kV transformer bushings

There have been a number of 66kV bushing failures on United Energy transformers over the past 15 years. The condition of all transformer bushings is monitored by a program of routine condition assessment. A bushing replacement program is in place driven by the results of these condition assessments and assessments of the failure consequence.

The replacement of bushings is not planned over the forward planning period for this DAPR, with a replacement required immediately, or within 6 months depending on the assessed condition of the plant. United Energy is not able to predict which specific substations will have a limitation introduced beyond the period specified. Therefore, the location and the timing of the replacement cannot be planned, and United Energy is not able to predict which specific substations will have a retirement and at which time.

15.2.12 Protection & control relays

Protection and control systems are critical to the safe and reliable operation of the network. These systems are designed to detect the presence of power system faults and/or other abnormal operating conditions and to automatically isolate the faulted network by the opening of appropriate high-voltage circuit breakers. Failure to isolate power system faults will invariably result in severe damage to network plant and equipment, presents a serious health and safety hazard to the public, and greatly increases risk of fire starts.

The relaying technology used to implement these protection and control systems has evolved and changed significantly over the past 50 years and can be classified chronologically as electro-mechanical, analogue electronic and digital electronic (including numerical) technologies.

The decision to retire and renew protection and control systems is based on a number of factors broadly including:

- Adopting programmed preventative maintenance coupled with planned relay replacement prior to failure based on asset condition and the most economic lifecycle cost (determined by risk and consequence of failures) and
- Aligning with other works at the zone substation where it is economical to do so (e.g. align with switchboard or switchyard replacement works).

Protection and control relays at a number of zone substations are approaching end of life. The table below summarises United Energy's forecast replacement activity over the next five year period. In accordance with United Energy's economic assessment framework, asset replacement is demonstrated to be the least-cost technically acceptable network solution when compared with the other network options including do nothing (replace on failure) and increased maintenance (replace on failure). The timing of each project is subject to an economic assessment using the most current input data.

Table 15.2 Relay replacement summary

Zone Substation	Replacement Driver	Forecast Replacement
GW	Risk assessment based on forecast failures and consequence and aligned with switchgear / control building replacement works.	2026 (committed)
EM	Risk assessment based on forecast failures and consequence and aligned with switchgear replacement works.	2026 (committed)
DVY	Risk assessment based on forecast failures and consequence of failure.	2026 (committed)
MTS	Risk assessment based on forecast failures and consequence of failure.	2027
CDA	Risk assessment based on forecast failures and consequence of failure.	2028

15.2.13 D.C. systems

D.C. supply systems are critical to the safe and reliable operation of the zone substation and is required to support the operation of protection and control systems amongst other things. The D.C. supply system consists of battery banks, battery chargers, distribution boards and associated management and monitoring systems.

The life of a battery bank is largely determined by its design and actual operating conditions. A battery capacity less than 80% of the nominal capacity means the battery is at end of life. Battery bank replacements are forecast based on failure history of individual battery models and consequence of failure. Shorter term replacement decisions are also driven by condition assessment (per results of planned maintenance and/or online condition monitoring). Battery banks usually fail within two years of the first signs of significant deterioration.

Each battery bank is kept on charge via the application of a battery chargers which has a typical life expectancy of between 15 and 20 years. Battery charger replacements forecasts are based on failure history of individual battery charger models.

Replacement of zone substation battery banks and chargers are considered in-conjunction with other asset replacement works at the target zone substation where it is considered economic and consistent with United Energy's economic assessment framework.

15.3 Summary of planned asset deratings

The rating of an asset is the rating at which the asset can operate reliably. Typically, this is generally set by the manufacturer of the asset, based on design criteria. However, where assets are operating beyond their design life, their condition may deteriorate such that a de-rating may be required to ensure reliable operation. This may be a prudent and more cost-effective option than replacing the asset.

United Energy's asset management strategies include for some assets (namely power transformers) the requirement to constantly monitor the asset condition, and to revise the cyclic rating based on;

- Observed differences between expected and actual asset performance;
- Identified condition assessment resulting in a different parameter to that assumed; during the previous rating allocation;
- Plant modifications;
- Changes in load profile affecting asset performance.

United Energy constantly undertake plant condition assessments, of which some assessments will be of key parameters that are used to determine the asset's rating. These assessments typically involve electrical, mechanical, moisture or thermal analysis. Any de-rating is promptly applied to manage risk once identified; thus, de-ratings are normally reactive in nature.

United Energy has no planned asset deratings in the forward planning period for this DAPR.

15.4 Committed projects

There were no committed investments worth $3 million or more to address urgent and unforeseen network issues.

16 Regulatory tests

This chapter sets out information about large network projects that United Energy has assessed, or is in the process of assessing, using the Regulatory Investment Test for Distribution (**RIT-D**) during the forward planning period for this DAPR.

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

Large network investments are assessed using the RIT-D process. The RIT-D relates to investments where the cost of the most expensive credible option is more than $7 million. The RIT-D has historically been used for large augmentation projects and was extended to include replacement projects from 18 September 2017.

16.1 Current regulatory tests

United Energy did not initiate or complete any new RIT-Ds in 2025.

Table 16.1 Completed RIT-D projects

N/A	
Description	N/A
RIT-D Completion Date	N/A
Options and Net Economic Benefit	N/A
Preferred Option Details	N/A
Further Information	N/A

16.2 Future regulatory investment tests

Based on the information contained within Chapters 7 and 15, United Energy expects to commence reviewing options to address the identified system limitations. The table below sets out the possible timeframes for consideration of RIT-D under Clause 5.17 of the NER relating to investments where the cost of the most expensive credible option is more than $7 million.

RIT-D consultation documents will be made available from the United Energy website and notified to participants registered on the Demand Side Engagement Register.

Table 16.2 Future RIT-D projects

Project name	Description	Proposed RIT-D start date	Further information
HGS-RBD line	New 66kV line	Feb 2028	N/A

16.3 Excluded projects

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

17 Network performance

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

17.1 Reliability measures and performance

United Energy is subject to a range of reliability measures and standards.

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

- system average interruption duration index (**SAIDI**): Unplanned SAIDI calculates the sum of the duration of each unplanned sustained interrupted customer minutes off supply (CMOS) divided by the total number of distribution customers. It does not include momentary interruptions that are three minutes or less;
- system average interruption frequency index (**SAIFI**): Unplanned SAIFI calculates the total number of unplanned sustained interrupted customers divided by the total number of distribution customers. It does not include momentary interruptions that are three minutes or less; and
- momentary average interruption frequency index (**MAIFIe**): calculates the total number of momentary interrupted customers divided by the total number of distribution customers.

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

The table below shows the reliability service targets set by the AER for United Energy in its Distribution Determination in April 2021.[12] United Energy reported to the AER its 2024/25 Financial Year performance against those targets in the 2024/25 Financial Year Regulatory Information Notice (RIN), and these figures are included in the table.

[12] AER, United Energy, Distribution determination 2021–2026, Final, April 2021.

Table 17.1 Reliability targets and performance

Feeder	Parameter	AER target (2021-2026)	2024-2025 performance
Urban	SAIDI	42.700	32.785
	SAIFI	0.688	0.412
	MAIFIe	0.956	0.837
Rural short	SAIDI	131.068	59.540
	SAIFI	1.926	0.658
	MAIFIe	4.288	1.671

In 2024/25 FY, United Energy achieved all reliability targets for Urban and Rural Short.

United Energy aims to continuously enhance its performance against the applicable performance targets outlined in the Service Target Performance Incentive Scheme, with a commitment to maintaining or exceeding these targets over the forecast period.

The following subsection highlights the measures United Energy has implemented to maintain and enhance reliability performance.

17.1.1 Corrective reliability action undertaken or planned

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

The processes and actions which United Energy undertakes to maintain reliability include (but are not limited to):

- undertaking the various routine asset management programs, including:
  - inspection of poles and pole tops
  - maintenance and replacement programs for overhead and underground lines, primary plant and secondary systems
  - testing of lines such as high-voltage feeder cables
- targeted installation of smart technologies to improve network monitoring, control and restoration of supply including automatic circuit reclosers (**ACR**s) and remote control gas switches (**RCGS**s), at strategic locations
- targeted reduction of the exposure to faults on the distribution network by using:
  - thermography programs to detect over-heated connections
  - vegetation management programs to improve line clearances
  - animal and bird mitigation measures to reduce the risk of ‘flash-overs’

  - conductor clashing mitigation measures to reduce the risk of 'flash-overs'
  - Analysis of LiDAR data to identify locations of conductor clashing risk
- network reconfiguration of the worst performing feeders to reduce the impact of faults
- conduct fault investigations of significant outages and plant failures to understand the root cause, in order to prevent re-occurrences
- continual improvements to outage management processes
- undertake asset failure trend analysis and outage cause analysis to identify any emerging asset management issues and to mitigate those through enhancing the related asset management plans, maintenance policies or technical standards

Evaluation of the 2024/25 reliability improvement initiatives should be considered in the context of the longer term goals stipulated above and the volatility caused by uncontrollable events such as severe storms and the effect of third party events.

17.2 Network Resilience

Our customers are facing more frequent and severe weather events like bushfires, storms and floods, while relying on electricity more than ever to power their daily lives. Customers tell us they want a reliable, resilient and safe network that can stay connected and withstand these events. They also want us to be more active and present in the community during emergency responses and get the power back on faster.

Based on their feedback, we plan to harden our network to extreme weather events and to help our local communities to prepare for, respond to and recover from extreme weather events including:

- Improve resilience for customers on the lower-Mornington Peninsula
- Enhanced climate modelling to enable better forecasting of extreme weather events
- More emergency response vehicles and customer liaison officers who know the local community to provide on-the-ground support during emergencies
- New technology to help prioritise how we respond during wide-scale outages and ensure communities have what they need.

17.3 Power Quality Standards and Measures

United Energy is committed to not only a reliable supply for all customers but also ensuring power is delivered at a high quality. The projects and initiatives on power quality by United Energy address power quality regulatory compliance requirements and maintain quality of supply levels on United Energy's network.

The regulatory obligations are to measure network power quality and to correct power quality where it is not within the specified limits. United Energy performs this by targeting power quality programs towards the worst-served customers first where there is an economically prudent case to do so. Furthermore, an increase in expenditure in some areas is required in response to increasing numbers of installed solar photovoltaic (**PV**) systems at customers' premises.

Power quality encompasses the parameters of steady-state voltages, voltage sags (dips), voltage swells (surges), flicker, harmonic distortion and unbalance of voltage for three-phase supply.

The main quality of supply measures that United Energy control are voltage and harmonics and are detailed further below.

17.3.1 Voltage

Voltage requirements are governed by the VEDCoP and the NER.

The NER requires that United Energy adheres to the 61000.3 series of Australian and New Zealand Standards. In October 2022, the VEDCoP was updated such that it more closely aligns with the NER requirements.

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

a) 230V;
b) 400V;
c) 460V;
d) 6.6kV;
e) 11kV;
f) 22kV; or
g) 66kV.

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

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

It should be noted that AS 61000.3.100 requires that the 99th percentile voltage must be less than 253V and the 1st percentile voltage must be above 216V. This is a deviation from the previous requirements that stipulated a hard limit of 216V and 253V. The VEDCoP also stipulates that the distributors would be liable for equipment and property damages should the steady-state voltage be found to operate outside 207V and 260V. The VEDCoP stipulates the abovementioned voltage levels should be at the meter closest to and applicable to the point of supply. AS 61000.3.100 also recognises that for distribution companies like United Energy, with hundreds of thousands of customers spread over a large geographic area, that achieving 100% compliance for all customers at all times is not economically or practically possible. Therefore, a network is considered to be 'functionally compliant' if it can achieve voltage within each limit for 95% of sites.

United Energy is able to measure voltage variations at zone substations, as many have power quality meters installed. It also now has access to voltage data at individual customer level through the Advanced Metering Infrastructure (**AMI**) metering.

Table 17.2 Permissible voltage variations[13]

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

17.3.2 Harmonics

Voltage harmonic requirements are governed by the VEDCoP and the NER. The NER, with which the VEDCoP now aligns, essentially requires that United Energy adheres to the 61000.3 series of Australian and New Zealand Standards.

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

[13] Table 2 Clause 20.4.2 of the VEDCoP.

Table 17.3 Voltage harmonic distortion limits

Odd harmonics non multiple of 3		Odd harmonics multiple of 3		Even harmonics	
Order h	Harmonic voltage %	Order h	Harmonic voltage %	Order h	Harmonic voltage %
5	6	3	5	2	2
7	5	9	1.5	4	1
11	3.5	15	0.3	6	0.5
13	3	21	0.2	8	0.5
17	2	>21	0.2	10	0.5
19	1.5			12	0.2
23	1.5			>12	0.2
25	1.5				
>25	0.2 + 1.3 · (25 / h)				
NOTE – Total harmonic distortion (THD): 8%.					

17.4 Power Quality performance

17.4.1 Steady state voltage

Power Quality Monitoring Data

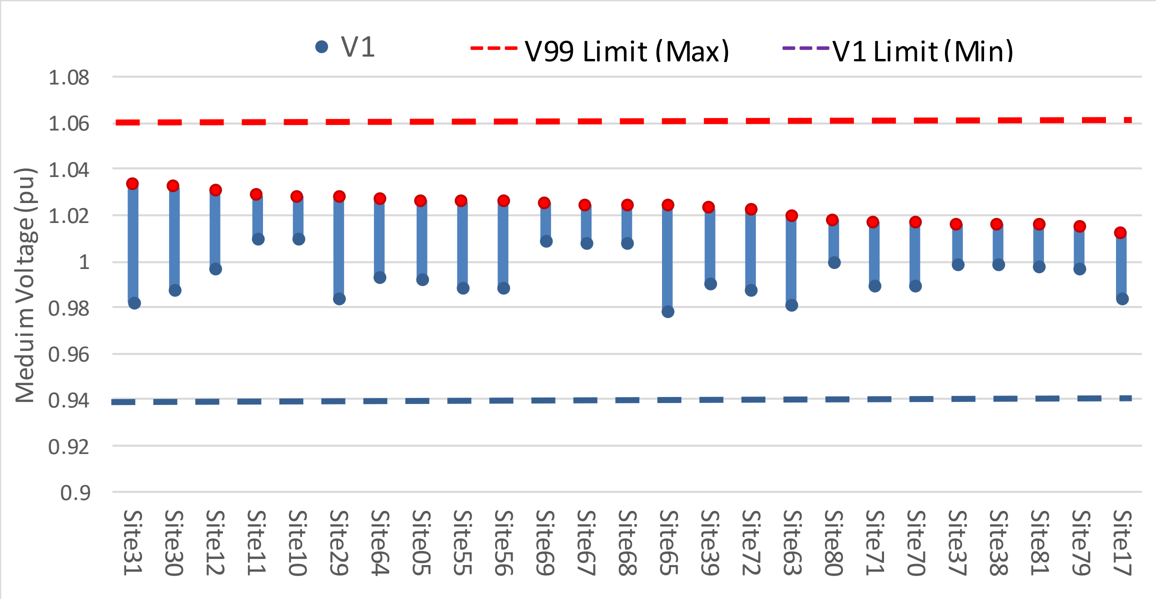
Power quality monitoring has been in service at our zone substations as well as towards the end of the longest distribution feeders for over 20 years.

We participate in the independent Power Quality Compliance Audit (**PQCA**) report independently prepared by University of Wollongong for The results are based on the medium-voltage power quality meters installed at each zone substation, and the low-voltage power quality meters installed at the start of one low-voltage circuit connected toward the end of the longest distribution feeder of each zone substation.

The figure 17.1 below shows the scatter plots of top 25 worst performing zone substations voltage levels at 99 percentile (V99) and at 1 percentile (V1) at V99 limit of 1.06 pu and V1 lower limit of 0.94 pu.

None of the zone substation medium-voltage sites exceeded the V99 limits nor the V1 lower limits.

Figure 17.1: Steady state voltage distribution for 25 worst performing Zone Substations



Distribution Limitations Template and AMI voltage data

AMI smart metering (deployed across the network less than 10 years ago), identified that there were a large number of customers experiencing steady-state voltages outside the regulatory limits; more regularly at the high voltage limit end (253V). This issue was previously largely unknown due to the absence of continuous voltage monitoring on the low-voltage networks and was subsequently revealed by United Energy's population of smart meters. These issues have been exacerbated recently by the increasing penetration of roof-top solar photovoltaic (**PV**) cells exporting power, further increasing voltages, and being limited in operation at customer premises.

The Electricity Distribution Code was updated in 2020 to include additional DAPR reporting requirements for United Energy, including AMI voltage information in a Distribution Voltage Information template, which has been published alongside this DAPR in MS-Excel® format.

The voltage information required to be published is for each voltage-controlled section of the network, which is defined as any device or equipment that manages the distribution feeder voltage, starting from the zone substation. Voltage information is therefore required and provided for each of United Energy's distribution feeders given it has no in-line voltage regulators.

The voltage data to be published for each section is the aggregated 10-minute average voltage data, aggregated over 3 months periods (December-November), by time of day into 6 hour periods (from 4am to 4am). United Energy has produced the 10-minute average voltage data by averaging its sampled 5-minute meter voltage reads.

The data required under the VEDCoP is average voltage data only. It does not provide granular information to determine steady-state voltage performance and non-compliances which is related to the minimum and maximum voltages at each customer point of supply.

A monthly breakdown of the network-wide average voltage from 5-minute voltage reads is illustrated in Figure 17.2. United Energy upper end V99 and the lower end V1 compliance percentage are with the 95% customer voltage compliance limit.

Figure 17.2 Monthly Average Voltage Nov 2024 – Oct 2025

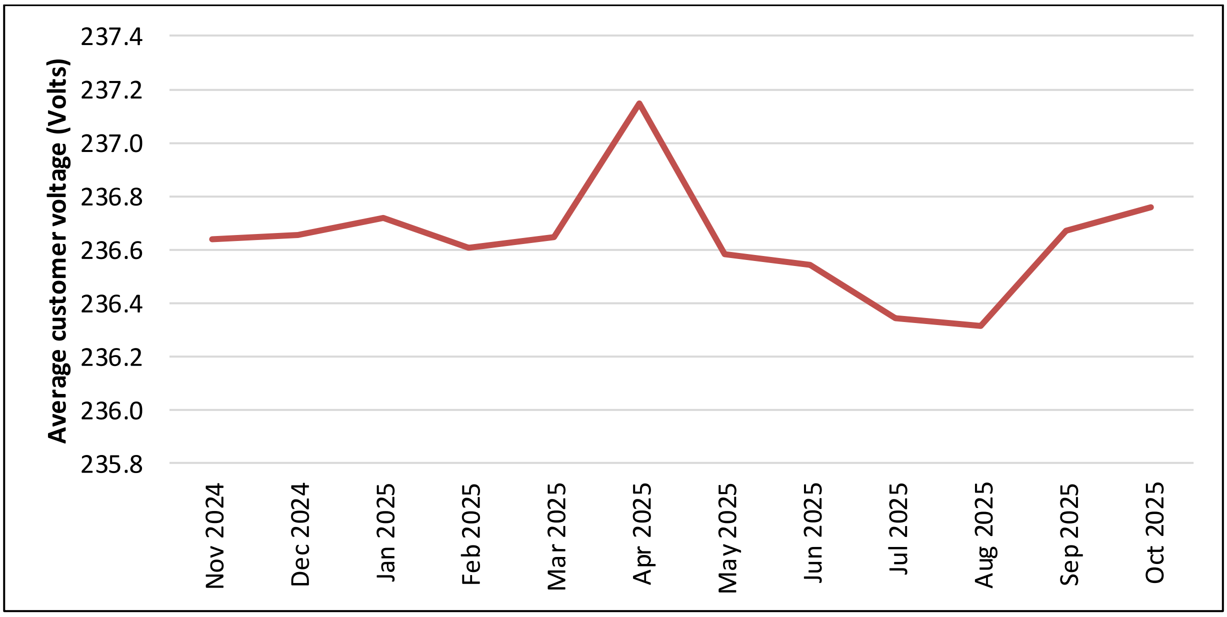


Figure 17.3 Monthly V99% 253V Customer Compliance Nov 2024 – Oct 2025

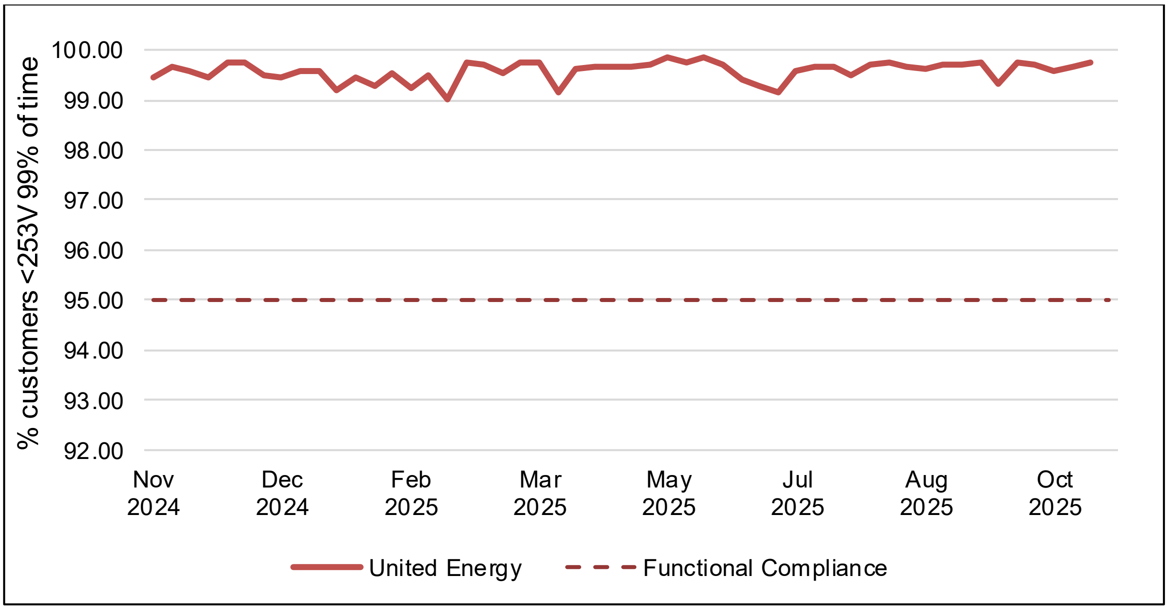
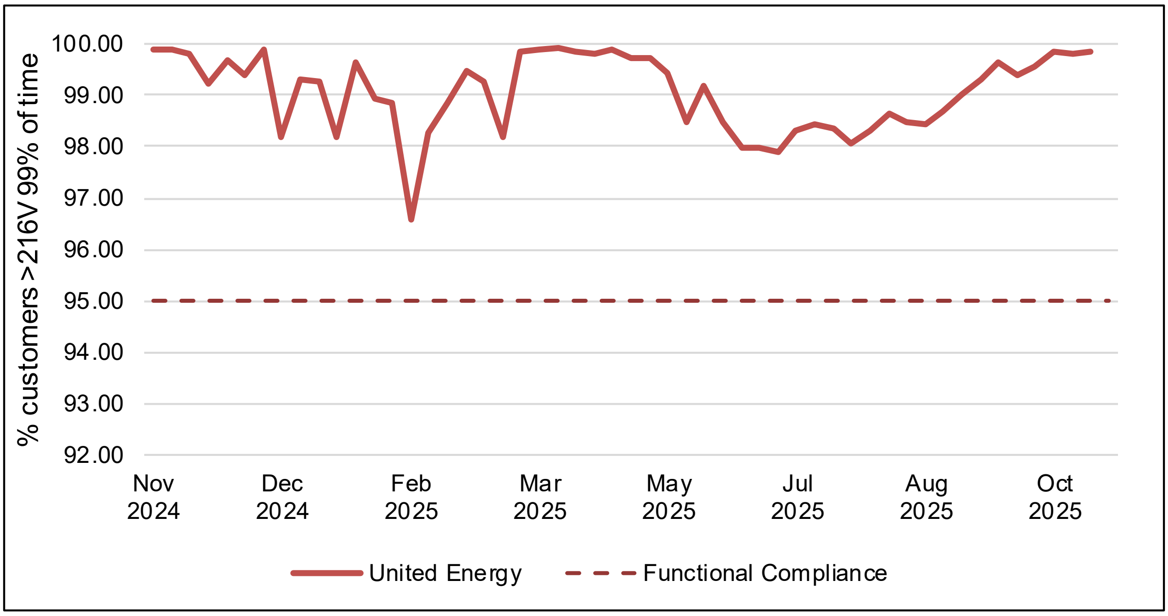


Figure 17.4 Monthly V1% 216V Customer Compliance Nov 2024 – Oct 2025

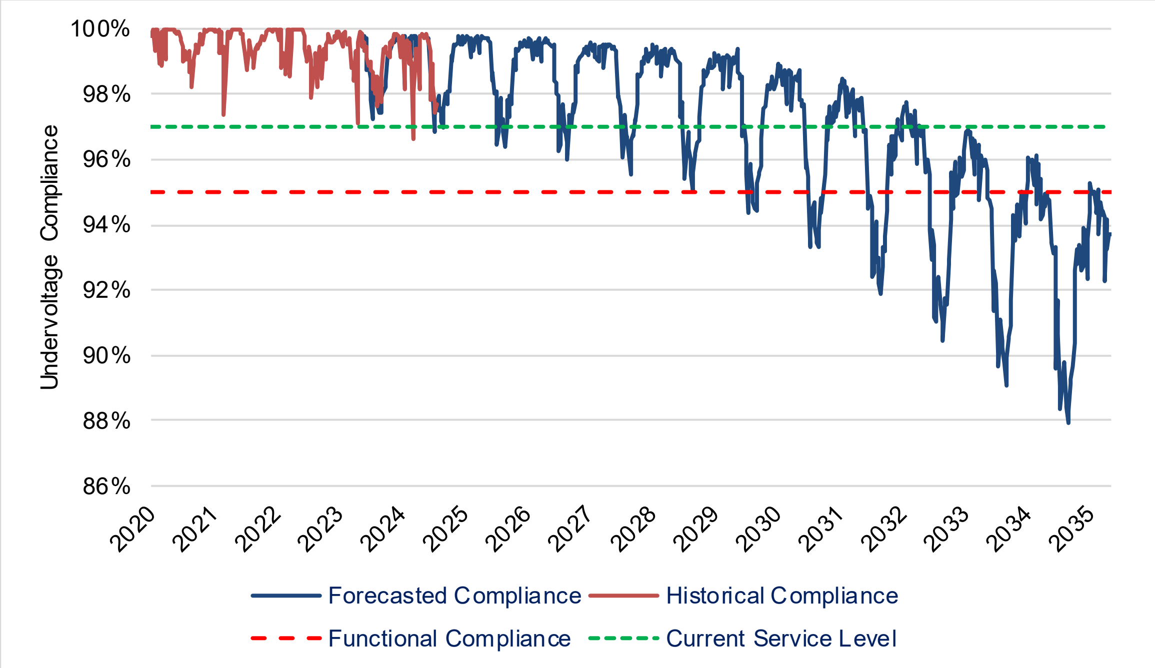


Since the installation of smart meters, United Energy has been progressively improving its voltage compliance across the network. Most notably in 2017, United Energy was provided a grant from the Australian Renewable Energy Agency (**ARENA**) to deploy Dynamic Voltage Management System (**DVMS**) technology for the purposes of supporting demand response. This deployment also resulted in step improvements in steady-state voltage compliance across the United Energy network.

More recently, United Energy determined an innovative enhancement that could be applied to its DVMS system which would allow United Energy to lower voltages under light load and high solar times when high voltages occur while not impacting peak demand times which are the likely under-voltage times. This enhancement was implemented in June 2021 which has led to a significant step up in compliance, with the V99 limit level currently operating within the 95% functional compliance limits. To maintain functional compliance continued optimisation is required to cater for solar and load growth on the network.

Solar PV inverter compliance to AS 4777 is a key priority area for United Energy to maintain voltage and improve Solar PV hosting capacity. On 1 October 2022, United Energy introduced a new commissioning sheet process to embed inverter compliance within our export approval system. Advanced DVMS analytics trialled throughout the period have allowed us to detect and verify compliance rates. Achieving near 100% installation compliance is crucial to maximising the amount of rooftop solar PV that can be accommodated on the network, whilst maintaining network-wide functional voltage compliance.

Figure 17.5 Undervoltage compliance historical performance and 2026-2035 forecast without investment



Historically, the undervoltage compliance has fluctuated throughout the year due to seasonal factors but remained above the current service level of 97%. However, as illustrated in Figure 17.5 our studies predict this to gradually deteriorate into the future due to further electrification through EV adoption and replacing gas appliances. To maintain service levels, United Energy intends to invest in major upgrades in the LV network to add intermediate substations and augment undersized conductors in a customer-driven electrification works program.

In the 2025 period, United Energy has also undertaken rectification works including tap changes, phase balancing, augmentation and other capital works at over 320 sites, benefiting more than 30,000 customers. This does not include DVMS enhancement impacts which also benefited customers across the network. Further details of DVMS and works being undertaken to rectify steady state voltage issues and connect rooftop solar PV are described in Section 17.5.

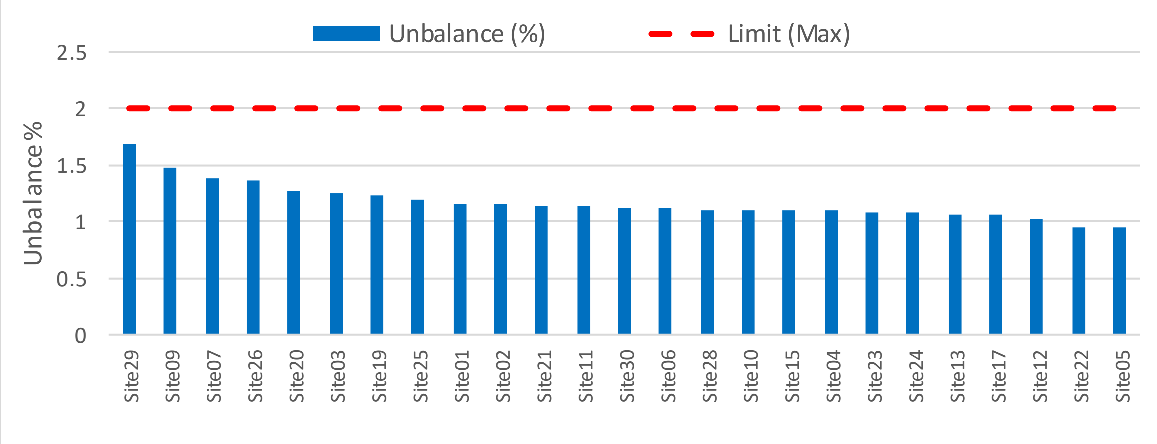
17.4.2 Voltage unbalance

Voltage unbalance is known to cause overheating in transformers and customer motors due to negative-sequence components created in the unbalance.

According to power quality meters connected at the zone substations, the voltage unbalance at all of the zone substation MV sites is within the requirements of the NER.

The Figure 17.6 below shows the voltage unbalance for 25 worst performing zone substation sites. None of the sites, voltage unbalance exceeded the required limits of 2%.

Figure 17.6 Voltage Unbalance at ZSS

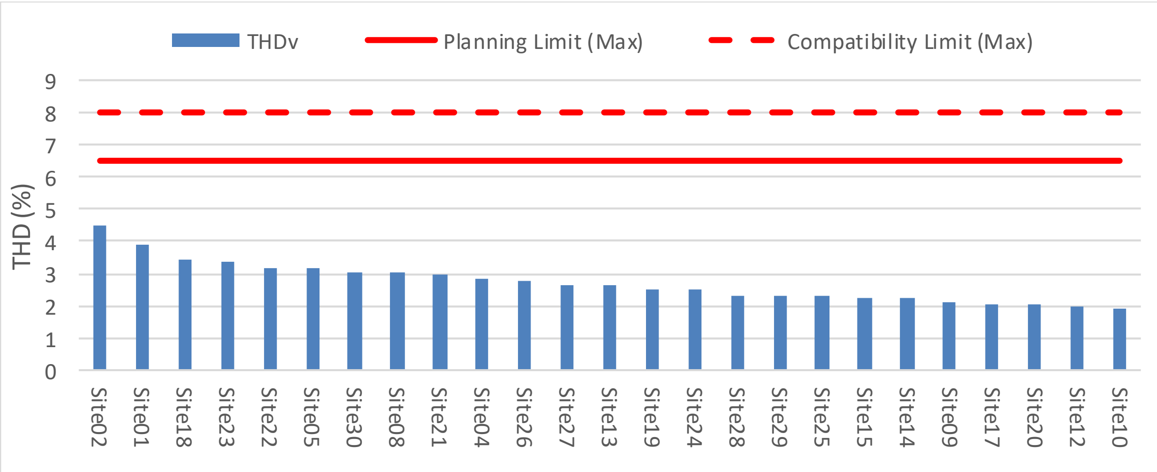


17.4.3 Voltage harmonic distortion

Voltage harmonic distortion can vary significantly across the network. According to the power quality meters connected at all the zone substation and monitored at medium-voltage levels, are within the requirements of the NER.

The Figure 17.7 below shows the voltage harmonics THD level at the 25 worst performing zone substations. None of the zone substation voltage THD levels exceeded the required limits of 8%.

Figure 17.7 Voltage harmonics distribution at Zone Substation Level



United Energy has observed fuse operations of capacitor banks on the network in the past which is directly attributed to harmonic resonance. Harmonic resonance can occur between capacitor banks and network reactance when the resonance frequency coincides with a harmonic frequency generated by non-linear loads. United Energy identified a number of problematic sites and installed various combinations of harmonic filtering and detuning reactors to address these issues. United Energy will continue to monitor harmonic voltage distortion and control harmonic levels going forward.

17.4.4 Flicker

In general, any load connected to the electricity network which generates significant voltage fluctuations can be the origin for flicker. Such voltage fluctuations are a result of significant cyclic variations, especially in the reactive component.

Causes of emerging voltage fluctuations may occur from micro-generation such as roof-top solar photovoltaic systems and micro-wind generation schemes. It is critical that the impact of these systems on our network is monitored and well understood.

The Figures 17.8 and 17.9 below show the long term and short-term flicker recorded at 25 worst performing zone substations. None of the zone substation flicker levels exceeded the required limits.

Figure 17.8 Zone Substation Short-term flicker

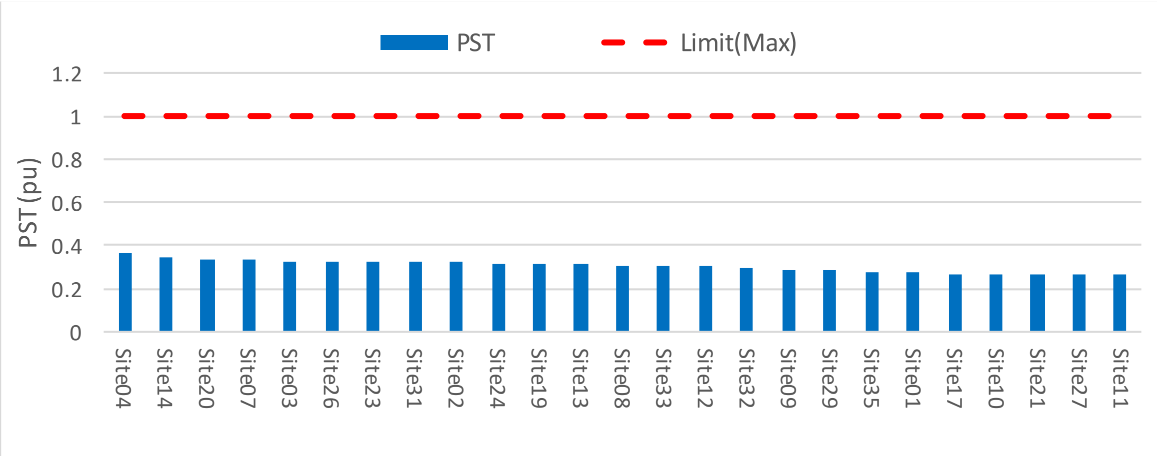
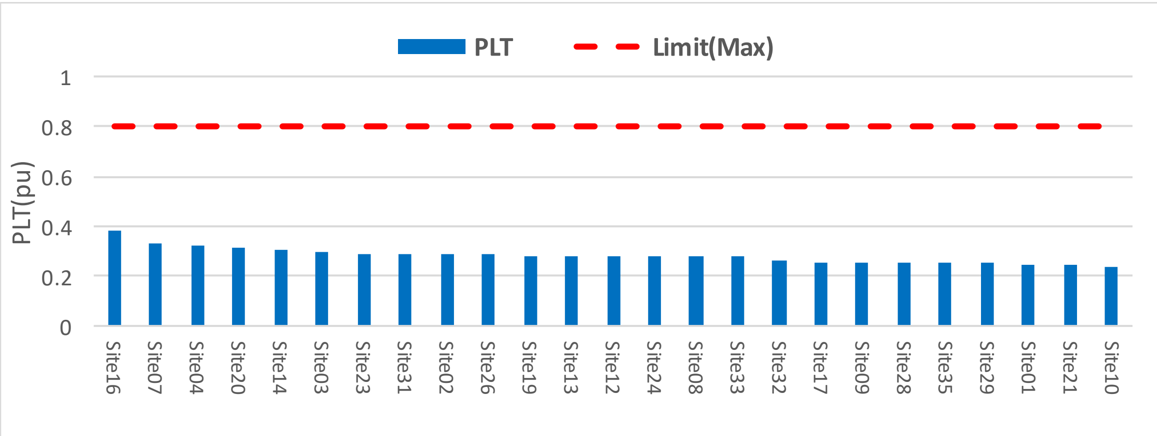


Figure 17.9 Zone Substation Long-term flicker



17.5 Power quality corrective actions and initiatives

United Energy has attempted to address the issue of voltage sags with a number of initiatives including improving reliability, limiting fault current, and dynamically changing the point of common coupling. United Energy intends to further address this issue by introducing several new technologies to minimise the severity of voltage sags experienced by customers by reducing the current flowing on the distribution feeders during a fault.

United Energy has recently completed or plans to undertake a number of initiatives in the area of power quality as discussed below.

Zone Substation Dynamic Voltage Management System (DVMS)

United Energy utilised grant funding provided by ARENA to deploy DVMS technology across the United Energy network in 2018 and 2019. The technology provides the benefits of delivering step-change improvements in steady-state voltage compliance and delivering demand response capability.

DVMS technology works by taking AMI voltage data for all customers and assessing this data (grouped by zone substation) using a data analytics engine. The float voltage of each zone substation is then adjusted dynamically to optimise voltage compliance. All of our zone substations now have this capability.

As described in 17.4.1 above in June 2021, United Energy implemented an enhancement to its DVMS algorithm which allows United Energy to lower voltages under light load and high solar PV export times when higher voltages occur while not impacting peak demand times. This has resulted in a further step up in the upper limit steady state voltage compliance. It should be noted that a number of United Energy's zone-substation transformers are now reaching their tapping limit at certain times, meaning that they are unable to lower voltages down any further without some form of augmentation.

Management of Rooftop Solar PV

United Energy has observed a significant increase in solar PV connections since the introduction of the Victorian Government Solar Homes Program. To mitigate against voltage rise from the accelerated uptake of solar PV, United Energy and the other Victorian DNSPs have adopted standard smart inverter settings to allow the networks to accommodate a greater amount of solar PV systems and their export. The Solar Homes program now mandates the use of smart inverters to facilitate the application of the settings, and the AER has approved the revised Model Standing Offer which specifies the required settings.

Also as mentioned in 17.4.1, during 2023, United Energy worked with manufacturers, installers, and customers that have identified issues, to rectify solar PV installations and inverter setting non-compliance issues and improve installation compliance going forward. To date, United Energy has been able to rectify over 10% incorrectly configured inverters through remote updates with manufacturers. This will be a continued focus going forward. Achieving near 100% installation compliance is crucial to maximising the amount of rooftop solar PV that can be accommodated on the network, while maintaining network-wide functional voltage compliance.

United Energy has continued implementing its Solar Enablement program to increase the network's solar hosting capacity and improve voltage compliance in areas where there are limitations. This includes continuing our dynamic voltage management system initiative, changing the tap setting of distribution transformers, balancing the load on low-voltage circuits, applying smart inverter settings on legacy sites, and undertaking targeted augmentation works where it is least cost and has a net economic benefit for customers. In 2024, United Energy has undertaken rectification works at over 300 sites benefiting up to 30,000 customers.

Low-Voltage Regulation

Application of a low-voltage regulator can potentially tighten voltage spread and provide faster response to sudden changes in voltage. They facilitate the connection of intermittent renewable generation by smoothing out flicker impacts. At present, the range of sizes for this equipment is limited and they have only been trialled in a small number of sites on United Energy's network. United Energy has assessed from the trials that low-voltage regulators can only be used economically in niche applications where both over and under-voltages are being experienced on some parts of United Energy's low-voltage network.

On-Load Tap Changer (OLTC) Distribution Transformers

The distribution transformers on the United Energy distribution network operate on fixed discrete taps and do not operate from an OLTC. However, there are some types of distribution transformer available on the market with an OLTC capability. United Energy has trialled such transformers to evaluate their performance at regulating the low-voltage and mitigating steady-state voltage variations as well as other benefits. It has been assessed from the trials that OLTC distribution transformers can only be used economically in niche applications where both over and under-voltages are being experienced on some part of United Energy's low-voltage network.

Terminal Station Power Quality Monitoring

Power quality monitoring is required at terminal stations to better understand power quality at transmission connection points and correlate this performance in the distribution network. Knowing the power quality levels at the connection points will enable United Energy to determine the components of power quality attributed to the transmission system, other DNSPs sharing connection points or distribution assets, or United Energy's own network. This will assist with a better identification of sources of power quality problems, enable United Energy to confirm power quality simulation models and identify common-mode power quality trends. It will also allow reporting of power quality levels at transmission connection points in the future if required.

This work will be coordinated with AusNet Services Transmission Group.

AMI Power Quality Monitoring

The rollout of AMI meters has enabled United Energy to monitor basic power quality levels at individual customer premises. United Energy has developed query and reporting tools to aggregate the data into meaningful sets of information and provide exception reporting to better manage the quality of supply to customers such as steady-state voltages, voltage sags and swells and phasing information. United Energy has enhanced the AMI architecture to provide an engineering user interface for customer power quality information and to facilitate investigations into poor power quality performance. The interfaces also identify phase unbalance and other power quality performance issues (such as loose connections) to facilitate identifying the most appropriate mitigation solutions.

Harmonic filtering

Harmonic filters are needed to manage the high levels of voltage harmonic distortion at some zone substations with the capacitor banks out of service or where multiple harmonic frequencies are problematic and where replacement of the inrush reactor alone does not achieve desired detuning effects. United Energy has already completed installation of harmonic filters at a number of zone substations and plans to continue to monitor any future need for additional filters at zone substations with high levels of voltage harmonic distortion, caused by resonance conditions, that exceed regulatory limits.

Bus-tie open scheme

This scheme limits the severity of voltage sags created by faults on the medium-voltage network by isolating the healthy parts of the network from faulted parts by switching circuit breakers. While this scheme does not reduce the number of faults on the network, it does limit the number of customers exposed to severe voltage sags during a fault, without compromising overall system reliability and plant utilisation. United Energy plans to install similar schemes at zone substations which are currently experiencing high number of voltage sags.

Distribution substation offloading

United Energy are planning to install new distribution substations (DSS) to offload parts of existing circuits. This will redistribute load to relieve capacity and voltage constraints on existing substations.

18 Embedded generation and demand management

This chapter sets out information on embedded generation as well as demand management activities during 2024 and over the forward planning period for this DAPR.

18.1 Embedded generation connections

The table below provides a quantitative summary of the connection enquires under chapters 5 and 5A of the NER and applications to connect EG units received between 1 December 2024 and 30 November 2025.

Table 18.1 Summary of embedded generation connections during 2024

Description	Quantity (>= 5MW)
Connection enquires under 5.3A.5	4
Applications to connect received under 5.3A.9	1
The average time taken to complete application to connect	14
Description	**Quantity (>= 30kW and < 5MW)**
Connection enquires under 5A.D.2	452
Applications to connect received under 5A.D.3	150

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

https://www.unitedenergy.com.au/partners/renewable-generators/

Key issues to connect embedded generators to United Energy's network include:

- Market developments significantly influence the economic viability of all generation type and scale, requiring specialised resources to manage evolving technical demands.
- Obligations and liabilities need to be assessed on a case-by-case basis and negotiated with the proponents, considering potential impact to other non-embedded generator customers as well as proponent's own installations.
- Technical standards and the regulatory framework lags behind market developments and new technologies.
- Project coordination challenges for complex proposals, given multiple parties are involved at various stages of the connection application process (i.e., United Energy / Connection Applicant / AEMO / Design consultants / Primary constructor and sub-contractors etc.).
- Testing and commissioning of EG installations challenges arise due to the diversity and spectrum of proponents and their capabilities, extending the application timeframe.

18.2 Demand management activities

Demand management is part of a broader range of non-network solutions designed to deliver lower cost solutions for the management of network limitations associated with maximum demand. United Energy defines non-network solutions as projects or programmes undertaken to meet customer demand by shifting or reducing demand on the network in some way, rather than increasing supply capacity through network augmentation. United Energy has led the industry with the implementation of several successful non-network solutions over the last several years and is keen to actively increase the implementation of non-network solutions over the forward planning period for this DAPR.

18.2.1 Network Support Agreements in recent years

Through our actions to promote non-network solutions, in the last five years United Energy has identified demand management solutions to successfully defer the proposed augmentation on two distribution feeders, CRM 35 and MGE 12, and on the lower Mornington Peninsula sub-transmission network.

United Energy committed to the implementation of a 13 MW demand-side solution on the lower Mornington Peninsula, from summer 2020-21. A demand side solution has been in place on the lower Mornington Peninsula since summer 2018-19 and was initially identified as a preferred solution through a Regulatory Investment Test for Distribution (**RIT-D**) consultation that concluded in 2016.

The required demand-side solution is reviewed in June of each year to determine total amount required for upcoming summer. Due to an increase in the numbers solar panels installed in the lower Mornington peninsula, total required demand side solution has been reduced to 10 MW.

18.2.2 Battery Energy Storage Systems (BESS)

In 2021, United Energy partnered with ARENA to trial LV grid-side BESS across United Energy's distribution network, with expected total combined capacity greater than 1.0 MW. United Energy has also partnered with Simply Energy to test the market benefits. To date 37 BESS units have been installed.

United Energy commenced Carrum Downs Community BESS project with funding support from Federal Government grant under the Community Batteries for Household Solar Program. This will be the first network-owned, ground-mounted community battery in the United Energy network. The battery will soak up excess solar from nearby rooftops and help reduce constraint during peak demand periods.

18.3 Actions taken to promote non-network solutions in the past year

United Energy has undertaken the following actions to promote non-network proposals in the last twelve months:

- In FY24, in partnership with Piclo Flex, UE launched an online flexible marketplace which offers an interactive map of local network constraints and information about the network needs in a particular area. This allows flexible service providers (FSPs) to easily match their solutions to network opportunities close to them. This platform allows for FSP to competitively tender their application.
- United Energy has maintained our Demand Side Engagement (DSE) Register for customers, interested groups, industry participants and non-network service providers who wish to be regularly informed of our planning activities. United Energy has also continued an initiative with CitiPower and Powercor to expand each distribution businesses' respective DSE Registers by identifying where potential businesses could provide non-network services across multiple areas.
- United Energy monitors industry developments and engages with providers of demand management and smart network technologies

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

18.4 Solar Microgeneration Units and Emergency Backstop

As required under the Ministerial Order (Victoria Government Gazette No. S 31, 31 January 2024), the following instances of interruptions or curtailments of electricity generation by solar microgeneration units have been recorded:

Note that the Emergency Backstop system went live on the 1st of October 2024, so the reporting period is from October 1st, 2024, to November 5th, 2025.

United Energy has not remotely interrupted or curtailed electricity generation by an emergency backstop enabled relevant solar microgeneration.

In accordance with subclause 8(1)(b), the number of relevant solar microgeneration units connected to the licensee's distribution system that are "emergency backstop enabled" is **6781 connections** as of November 5th 2025. Note that connections were made post October 1 2024.

The total aggregate capacity was **58.12MW**.

This number of connections and capacity represents the cumulative generation potential of all connected units that are emergency backstop-enabled to the extent of United Energy's knowledge.

From March 14th 2025 to October 31st 2025, the total time that the utility server was offline for unplanned reasons was 36hr and 44mins. The data is not available for tracking the time offline prior to March 14th.

18.5 Demand side engagement document and register

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

https://media.unitedenergy.com.au/factsheets/UE-FW-0001-Demand-Side-Engagement-Framework.pdf

United Energy has also established and updated its DSE Register. To register as an interested party on the DSE Register, applicants should fill out their details on United Energy's website at:

https://www.unitedenergy.com.au/demand-side-engagement-form

19 Information Technology and Communication Systems

This chapter discusses the investments we have undertaken in 2024, or plan to undertake over the forward planning period for this DAPR 2025-2029, relating to Information Technology (**IT**) and communications systems.

19.1 Security program

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

Through our Cybersecurity strategy, we have delivered security uplift programs to our email security, network security and identity platforms. Our current in-flight projects will progress into 2026 and deliver on uplifting our operational technology (OT), training and awareness programs, and cyber response and recovery capabilities. Our current cyber security strategy will be fully delivered by 2026. We have completed the development of the next phase of our strategy for 2026 to 2031 and our current program of work will transition seamlessly into the future strategy. We have met all current requirements under the SOCI act, including the Risk Management Program (RMP) Cyber and Information Security Hazard rules (Australian Energy Sector Cyber Security Framework (AESCSF) V1 SP1 compliance). We remain on target to meet additional requirements in 2026.

As part of our cybersecurity assurance program, we also conduct a series of formal and applied assessments that ensure the effectiveness of our controls and procedures. These include formal audits, penetration testing and simulated responses to a broad range of threat scenarios. We also participate in the yearly AEMO Trident exercise further enhancing our Cybersecurity Incident response process and procedures.

We will continue to align our security strategy and initiatives to address the changing threat landscape, ensure compliance with the SOCI act, and relevant industry standards such as AESCSF V2, and authorities such as Australian Signals Directorate (ASD) / Australian Cyber Security Centre (ACSC) to ensure that controls implemented are consistent with recognised Australian and international best practices.

19.2 Currency

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

In 2025, we continued the following upgrades:

- Supervisory Control and Data Acquisition (SCADA) Modernisation project – this initiative will improve the resilience of SCADA particularly in escalation events and improve the stability and throughput of the interface between SCADA and the Advanced Distribution Management System (ADMS)
- Field Collection System (FCS) – for MFA security compliance and enhance FCA application and infield tablet to support new type of meter (Secure DLMS). However, this been on hold since late 2024 due to Secure firmware issues, project recommencement is pending Secure.
- MTS / IEE – Itron has advised that we need to upgrade the software in readiness for the functionality required to support the Flexible Trading Arrangements Rule change due early 2026. These upgrade projects commenced in 2024, completing in 2026.
- Webmethods – completed the upgrade to ensure ongoing support and currency

In 2025 we also commenced the following upgrades:

- Network Viewer upgrade – this included upgrading the enterprise solution for network visualisation underpinned by GIS. Upgrading the software and hardware has enabled performance, functional, security and support benefits.
- Upgraded our API gateway capability to improve the security and performance of integrations between on premise and cloud applications
- UIQ/SIQ upgrades commencing 2025, looking to complete in 2026 ahead of the next meter replacement program.
- OUNMS infrastructure upgrade to reduce maximum system outage time from 4 hours to under 30 minutes, with enhanced redundancy and a disaster recovery site enabling live failover, scheduled for completion in 2026

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

- Market system upgrade – uplift capability of market systems applications, which support market transitions and data to be provided to the market, note IEE/MTS listed above and UIQ/SIQ is commencing in readiness for meter replacement program. Geospatial Information System (GIS) upgrade – this will include a major upgrade targeted to commence in 20266
- Future Grid analytics engine upgrade – this upgrade will ensure currency of our core smart meter data pre-processing engine, that supports our inhouse Network Analytics Platforms. This upgrade is targeted to commence in 2026

- ADMS Upgrade – this upgrade will ensure that we maintain resilience and currency of our ADMS so that we can continue to manage the network effectively – targeted to commence in 2027

19.3 Compliance

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

In 2025 key activities for market systems are:

- A number of remediation projects for DERR and CDN to ensure ongoing compliance is maintained and systems are operating efficiently in preparation for Flexible Trading Arrangements (FTA)
- Commenced projects in readiness for AEMC's rule change FTA, for compliance to the two new metering types of Type 8 and Type 9.
- Enhanced our systems to support Industry Change Forms (ICF) arising from market participants and AEMO identifying market processes that require correction or improvement.
- Updates to systems resulting from AEMO's Metering Services Review and B2B 3.9 changes.
- Preparation for the next regulatory reset period of 2026-2031 for changes to Tariffs and Alternative Change Services.
- Continue to monitor the NEM Reform roadmap, with active involvement in AEMO's MITE forums and Customer Data Exchange.

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

19.4 Infrastructure

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

During 2025 we established new and enhanced existing applications, some supported by public cloud-hosted infrastructure and some supported by our own on-premise infrastructure. This meant we needed to expand or replace our infrastructure to support the business needs.

This included:

- We established our strategic approach to application hosting and moved towards software-defined architecture, allowing our current and future IT applications to select the most appropriate enabling infrastructure.
- Upgraded our data centre interlink that was end of life and experiencing bandwidth issues. The upgrade has given us higher speed links and mitigated operational risks due to network congestion.
- Refreshed critical network infrastructure to ensure we were on a supportable solution, have the capacity to accommodate increasing network traffic volumes and provide the ability to protect our devices against cyber-attacks.
- Refreshed critical network security “firewall” devices to ensure we were on a fully supported solution to enhance our availability for users.
- Continued deploying new meeting room technology across our offices and depots to enable efficient operations.

Over future years we will continue to assess the most appropriate infrastructure solutions, increasing adoption of cloud-based technologies where it is the most beneficial option.

19.5 Customer enablement

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

Over the past year we have continued to deliver high quality services to our customers, responding to their needs with robust feedback loops and the development of a range of IT enabled solutions.

Highlights of our customer enablement works include:

- New pole-mounted EV chargers are being rolled out in a special pilot across United Energy. After receiving a conditional ring-fencing waiver to conduct the trial, a number of pole-mounted EV chargers will be installed across United Energy providing customers an affordable and reliable public charging option. This brand new service represents a new offering for customers and community members within our network area
- The development of an AI transformation program aimed at driving operational efficiency and improvements for both customers and employees has launched. The program includes seven workstreams to explore AI opportunities to reduce administrative effort, deliver improved and consistent outcomes across key processes and deliver efficiencies
- We have continued to deliver outcomes for advanced distributed energy resource management systems works to ensure compliance with regulations but also deliver compliant systems for our customers ensuring they can optimally contribute their excess energy to the grid. This work involved detailed engagement, consultation, system testing across the industry for the betterment of our customers. This year

we have continued with trials for flexible services whilst also delivering compliance outcomes for Victoria's 'emergency backstop' requirements
- We have delivered a range of safety and energy literacy campaigns to support customers with important information. These have included campaigns promoting powerline safety to prevent contact with our assets, emergency and outage preparations, translation for CALD communities and affordability promotion regarding downloading consumption data
- Continued customer experience survey program to gain voice of the customer insights and identify customer focused improvements to deliver. The 2025 program engaged more people, more often about more services than ever before through a mix of telephone and online surveys.

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

Faults communication continued to be a focus of 2024 where system enhancements were embedded and monitored to reduce unnecessary ETR notifications received by customers, to issue alternative 'Restore' messages where customers have a defect and improve the display of outage information on the corporate website.

In addition to system changes, our second on-the-ground vehicle, Vehicle for Engagement Response and Assistance (VERA), was deployed to support vulnerable customers and communities during outage events and used as a promotional asset to drive energy literacy amongst communities at particular events. During a major storm event in February 2024, our emergency vehicles were deployed to support customers in Oakleigh and Mulgrave.

Further enhancements to our digital offerings enabled customers to get more control over who receives outage notifications for their properties and via which channels, enhanced accessibility of our digital tools and upgraded user interfaces. Additionally, we completed works to ensure Security of Critical Infrastructure (SOCI) Act compliance which included rolling out multi-factor authentication for all of our customer facing portals.

The Customer strategy refresh work completed in 2023 has progressed in 2024, targeting improvement across 10 key focus areas. Highlights of this work include:

- A refreshed brand campaign to improve awareness and energy literacy amongst our customers and communities along with a new brand tagline – 'essential as.' to position our business as an essential service in the eyes of our customers

- Advanced distributed energy resource management systems works to ensure compliance with regulations but also deliver compliant systems for our customers ensuring they can optimally contribute their excess energy to the grid. This work involved detailed engagement, consultation, system testing across the industry for the betterment of our customers

- A refreshed customer experience survey and insights approach for 2024 aimed at engaging more people, more often about more services through a mix of telephone and online surveys. In all, we were able to engage over 2,500 United Energy customers across 10 services and feed insights into an improvement program that has delivered more than 500 improvements since first being introduce in 2020

- Customer service online training, for new and existing employees, emphasising a culture where employees provide the customer with options, feel empowered to make decisions and have empathy for the customer's circumstances has been developed and rolled out. Over 98% of our customer facing teams have completed the training.

19.6 Becoming a more digital network

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

Through 2025 we continue to deliver on a number of initiatives including:

- Implementing improved distribution network modelling scenarios using our Network Hosting Capacity application. This application allows us to produce granular long-term forecasts on network hosting capacity, critical for identifying constraints and informing targeted and well-timed network investment.
- On-going implementation of the Victorian Government mandated Emergency Backstop capability. This means all new solar (PV) systems are required to have a way for network distribution businesses to limit solar export and production when required by the market operator (AEMO). For residential and small commercial customers this capability is via a technical standard called CSIP–AUS which uses the internet. For commercial and industrial customers, a generator monitor meter (utilising our AMI mesh infrastructure) is required as part of the installation, and for large (high voltage) generators they are connected to our HVDERMS system via dedicated communications equipment. This capability enables us to remotely ramp down or switch off customers with solar during a minimum demand event, avoiding wide-scale power outages. In 2025 we are investigating the use of CSIP-AUS as a potential mechanism for commercial and industrial customers.
- Trial an implementation of Dynamic Operating Envelopes (DOEs), which define the limits for exporting or importing energy dynamically based on network conditions, for commercial customers and residential customers to improve overall solar hosting capacities, via a Flexible Exports Trial.
- Engage with industry (which has included AEMO, retailers, and OEMs/Clean Energy Council etc) on how flexible connections (DOEs) can support market initiatives such as virtual power plants so that the distribution network capacity is utilized as much as possible before the need to do any physical augmentation.
- Continue to engage with the industry on non-network solutions via a flexibility marketplace (procurement platform).

Part of the digital revolution is being able to provide more information on how the electricity network is performing in more usable formats. This is the start of a "digital twin" journey for United Energy. Currently we utilise our fleet of helicopters and drones to provide 3D digital imagery which is used for improving our vegetation management, particularly for preparation associated with fire season. These data sets also help improve asset inspections for items such as power poles.

This data along with external data sets (such as flood modelling) are being used help improve our decision-making during major events that impact the network and our ability to supply our customers.

Over the forward planning period we will continue the Digital Network journey by focusing on enhancing asset data models, network granularity and forecasting, data quality, and analytics to further improve how we manage the network. This is all part of the distribution system operator journey and how we as United Energy do our bit to unlock customer value in their CER assets.

19.7 Field communication system investments

To facilitate and maintain the protection, control and supervision of the network, we have continued to invest in Supervisory Control and Data Acquisition (**SCADA**) and associated network communication and control equipment. This is used to monitor and control the distribution network assets, including zone substations and feeders.

In 2025 we have focused on the following:

- Commenced scoping the introduction of MPLS technology to ease capacity issues on some sections of United Energy's optical fibre network. MPLS equipment had been procured for testing purposes and will be used as a proof of concept to ensure it meets requirements. It is expected that MPLS will be deployed in a larger fashion from 2026 onwards.
- Replacement of GPS clocks for zone substations.
- Introduction of AEMO ICCP links to facilitate the connection of large generation customers on the United Energy network.
- replacement of aged Trio radio network which connects pole top devices to SCADA.

Over the forward planning period for this DAPR, we will continue to invest in SCADA technology, that is consistent with the growth and complexity of the network. Our SCADA expenditure will continue to modernise the communications network to support adequate capability and capacity by installing larger systems.

Specifically, we are planning to invest in the following:

- MPLS technology – a significant portion of our optical fibre network is highly utilised. Due to strong growth in the electricity network (driven by demand in area such as data centres and renewable generation), we have a need to improve capacity on the optical fibre network. Augmenting optical fibre is very expensive, instead we will be implementing MPLS as a cost effective way to improve capacity.
- Replacement of Aging RTUs – A number of aged zone substation RTUs will have reached end of life and are no longer available as spares. We will be replacing RTUs that represent the highest risk to the network.

20 Advanced metering infrastructure benefits

This chapter discusses our use of advanced metering infrastructure (**AMI**) technology and how information generated by AMI is being used to better support life support customers, guide network planning and demand side response initiatives, and support network reliability initiatives. AMI technology is also being leveraged in our digital network initiatives presented in section 19.6 above.

20.1 Life support customers

We are using our AMI technology to service and support our vulnerable customers more effectively, allowing us to keep our communities safe.

We are keeping our customers and communities safe by being alerted to life support customers off supply more quickly through our AMI meters across our network. Our systems alert us if the supply to an AMI meter associated with a life support customer fails, enabling us to more quickly resolve supply to the customer. This is key to our response planning for customers off-supply and allows us to understand the criticality of the disruption.

Our AMI technology also assists us in rotating load in emergencies. By rotating load, we can share energy among our customers in times of emergency. As such, we can prioritise life support customers in these cases to ensure their power remains on.

We plan to continue to leverage AMI data and services to develop further benefits for our customers, including life support customers, over the forward planning period. An example of an initiative we are currently working on, (which is reliant on our AMI) includes more accurate mapping of customers to their supplying Low-Voltage (**LV**) transformers, to help keep more life support customers connected during emergency load shedding and provide more accurate communications to customers of planned outages.

20.2 Network planning and demand-side response

AMI technology has been critical in allowing us to innovate in the way we operate the network and deliver effective customer service. Visibility of the LV network has improved customer outcomes through more efficient network management, improved network safety and reliability outcomes and improved responsiveness to customer needs.

Our AMI meters provide us with the ability to improve safety by identifying neutral faults at customer premises. Our systems alert us if the supply to an AMI meter has a neutral fault enabling us to more quickly resolve it. The system identifies unsafe situations as they develop, so corrective action can be initiated immediately. This is key for maintaining safety for our network and our customers.

Using the Victorian AMI specification also allows us to manage voltages and prevent load shedding and blackouts on peak demand days.

Further, the Victorian AMI is vital for enabling growth in distributed energy resources such as rooftop solar PV, batteries and electric vehicles. AMI provides us with the information to manage the network and accommodate the dynamic and less predictable energy flows that result from the increasing uptake of DER technologies by Victorians. We also use our AMI data for more accurate spatial demand forecasting, ensuring we optimise timing of network augmentation. Information from our AMI meters also assist us with detecting of customers with solar PV connections that are not registered as solar PV customers and/or are exporting more than they are contracted to export.

Our AMI technology is also an essential input into our Digital Network program which will enable more demand response initiatives through our proposed DER management system, as well as enable us to accommodate more solar within the existing network capacity. We plan to continue to leverage AMI data and services to develop new benefits for customers over our DAPR forward period. The following are some examples of initiatives we are proposing and implementing under our Digital Network program which are reliant on our AMI:

- Promoting electric vehicle uptake – monitoring and optimising EV charging to understand and estimate the impact of increasing demand on the distribution network resulting from EV penetration.
- Optimising load control of customer appliances – optimising existing hot water load control and enabling new load control programs (e.g., air conditioners and pool pumps), including through utilising excess solar in the middle of the day.
- Enhancing cost reflective incentives – analysing AMI interval data to construct more effective demand management incentives and time-of-use tariffs to reduce peak demand. This would improve overall utilisation of the distribution network, resulting in lower prices.
- Detecting electricity theft – identifying sites with bypass connections and reduction of theft, as well as identifying unregistered DER, often necessary in assisting pole investigations.
- Proactively managing asset failures—resulting in fewer fire-starts and avoided replacement expenditure.
- Avoiding overblown fuses—improving phase balancing, which will allow greater asset utilisation (and therefore reduce augmentation) as well as avoiding replacement expenditure from blown fuses.
- Minimum demand management – by shifting loads such as hot water connected to the meter and increasing network voltages to cut back the solar generation, we can manage minimum demand that is becoming more evident as renewable energies become more prevalent.

20.3 Network reliability

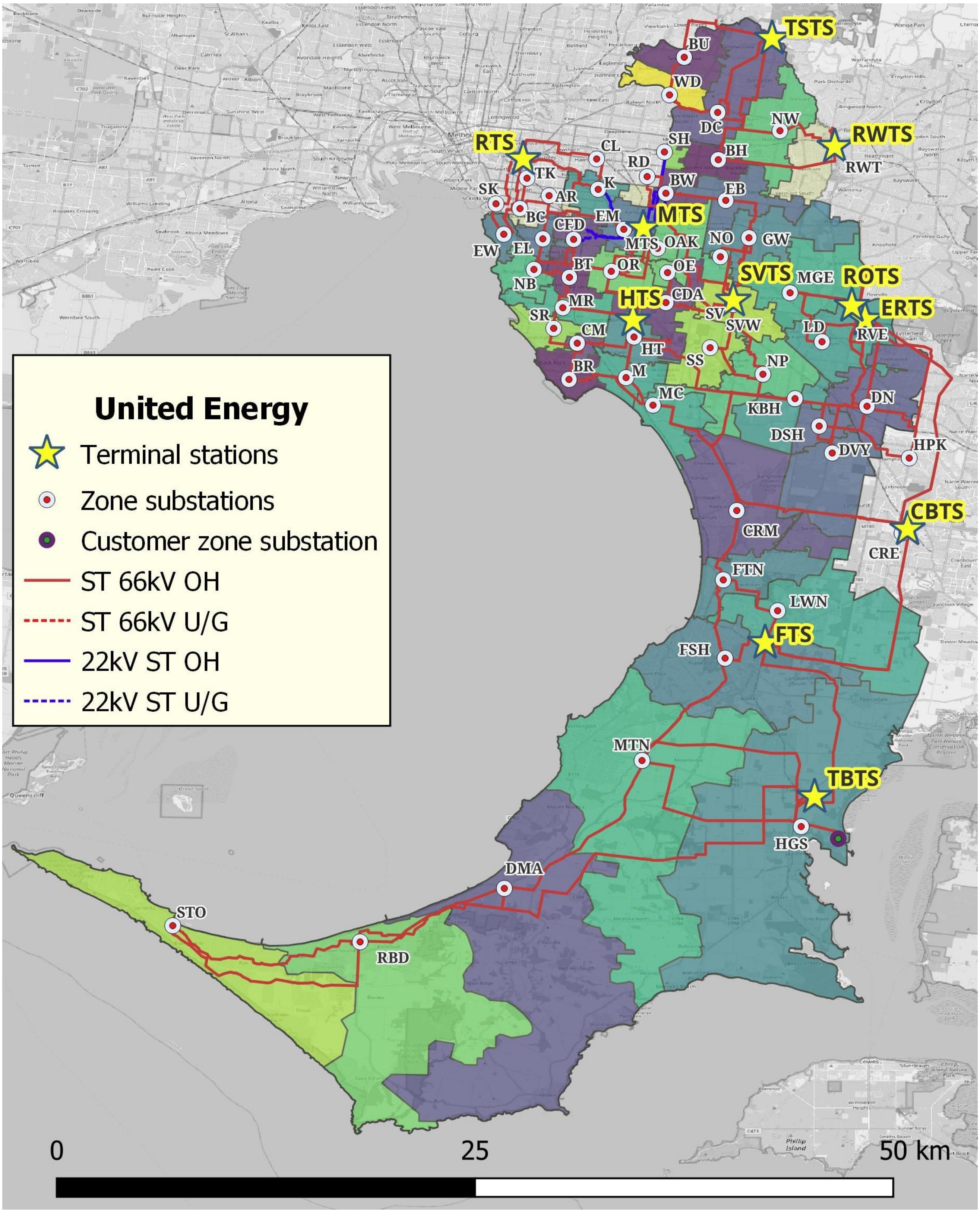
AMI information is being used to support our network reliability measures. We have shorter outages due to earlier identification of faults and more efficient restoration. This is because AMI meters give us almost instant notification of customers going off supply. We receive immediate notification of outages from the AMI meter which feeds into our outage management systems and automatically schedules and dispatches field crew to restore supply.

AMI meters also allow us to monitor basic power quality levels at individual customer premises. We have developed query and reporting tools to aggregate the data into meaningful sets of information and provide exception reporting to better manage the quality of supply to customers such as steady-state voltages, voltage sags and swells and phasing information. We have enhanced the AMI architecture to provide an engineering user interface for customer power quality information, and to facilitate investigations into poor power quality performance. The interfaces also identify phase unbalance and other power quality performance issues (such as loose connections) to facilitate identifying the most appropriate mitigation solutions.

Our AMI technology also allows for supply capacity control enabling us to more effectively target load shedding to minimise loss of supply impacts.

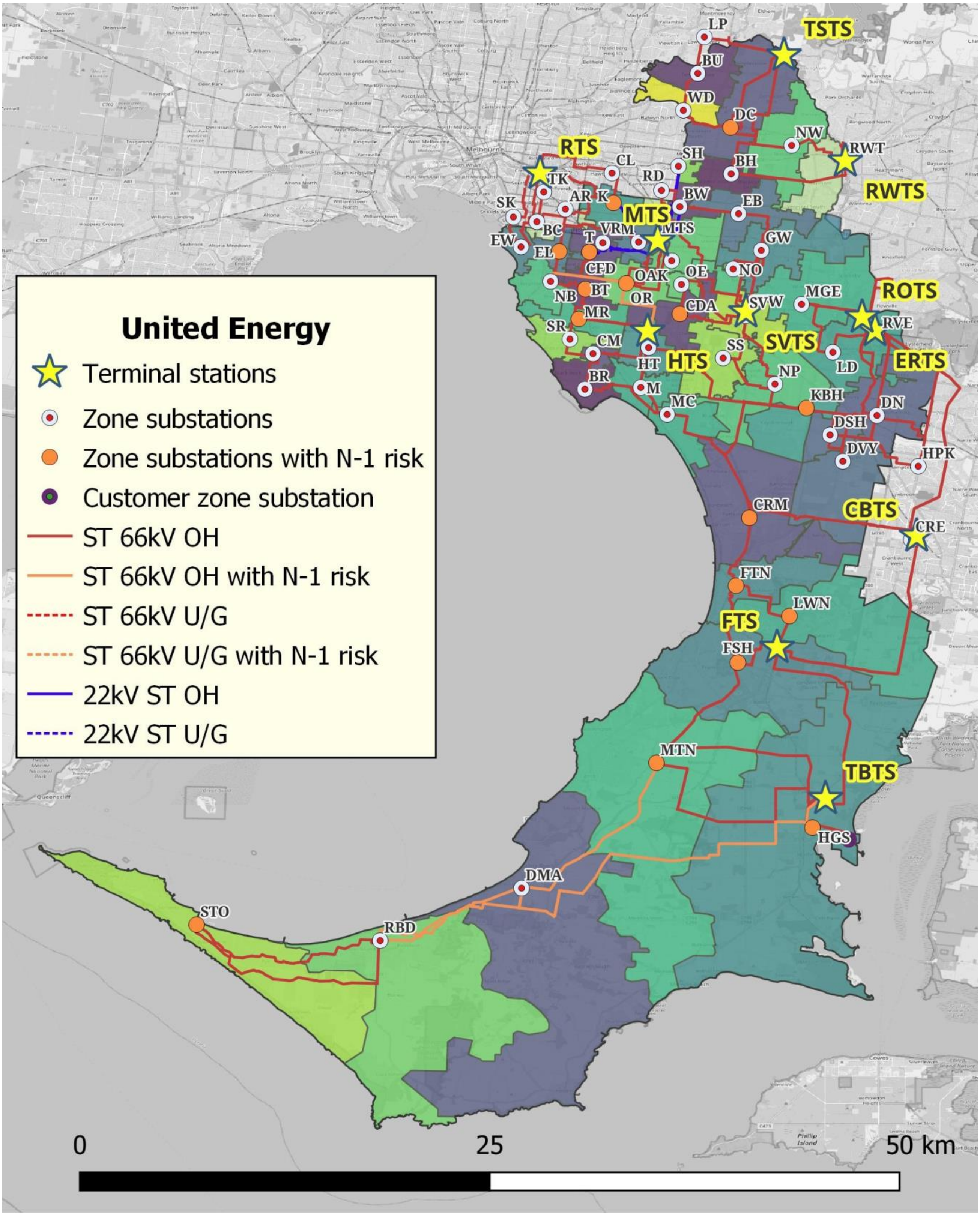
There is also improved quality of information and customer services during outages. We have developed an Interactive Voice Response service and SMS service which automatically advises customers of outages identified in a timely way through the last gasp AMI function. The quality of supply of information throughout the network is also enabling better network load profiling, identification of safety risks and improved voltage management.

Appendix A Network maps

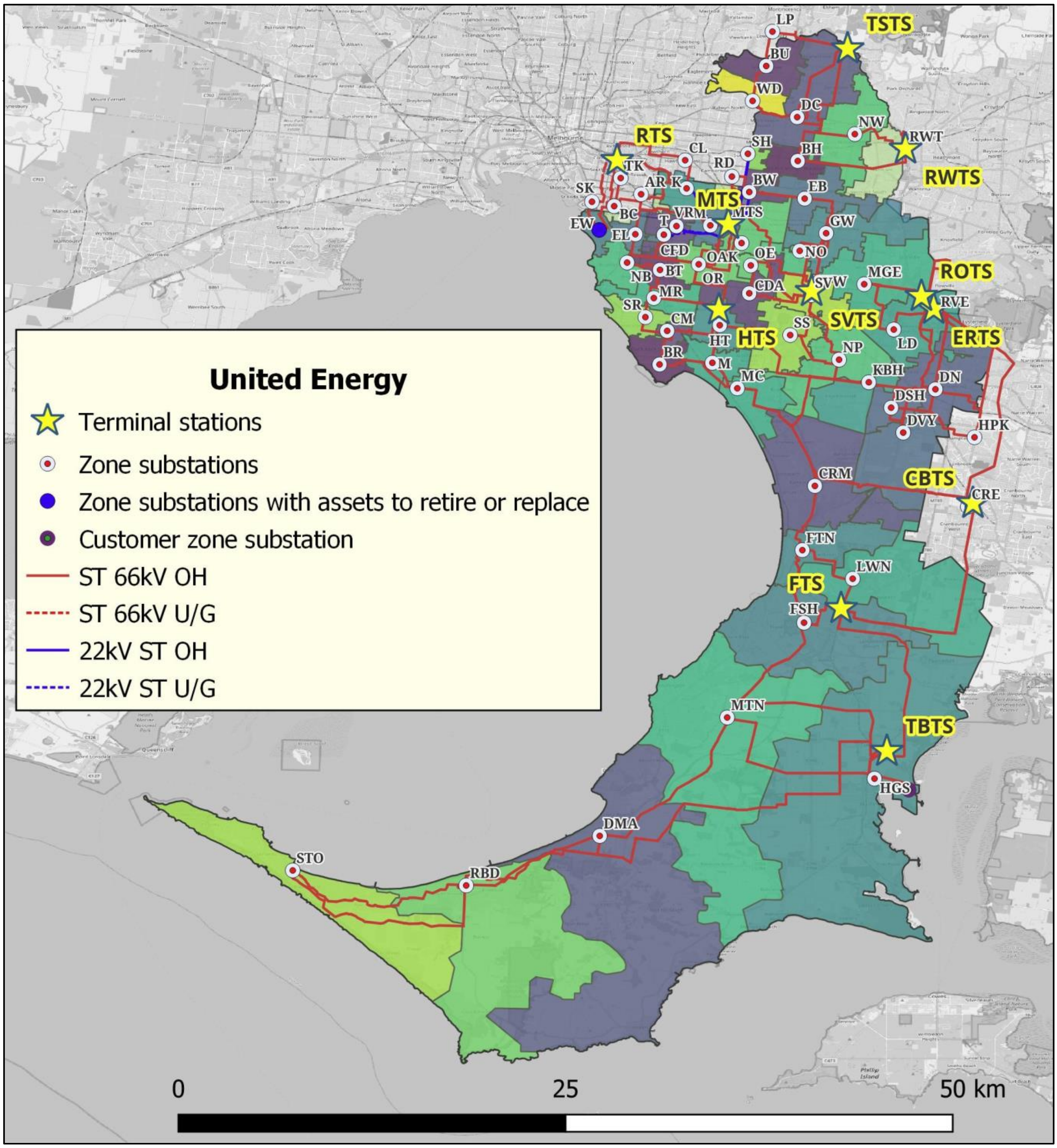


Appendix B Maps with forecast system limitations

B.1. Zone-substation and sub-transmission limitations (Augmentation)



B.2. Zone-substation transformer and switchgear limitations (Replacement)



Appendix C Glossary and abbreviations

C.1. Glossary

Common Term	Description
N Cyclic Rating	The available capacity with all network elements in service. Cyclic ratings assume that the load follows a daily pattern and are calculated using load curves appropriate to the season. Cyclic ratings also take into consideration the thermal inertia of the plant.
N-1 Cyclic or "Firm" Rating	The available capacity assuming the most critical network element is out of service.
Import rating	Import ratings define the network capability to transfer forward power flows (i.e., flows downstream towards customer loads) at that location.
Export rating	Export ratings define the network capability to transfer reverse power flows (flows from that location upstream towards the transmission point of connection).
Maximum demand	The highest amount of net electrical power imported (or forecast to be imported), from the grid to supply customers (in aggregate) for a particular season (summer and/or winter) or the year. This is also referred to as the peak load, as seen by the network.
Minimum demand	The lowest amount of net electrical power imported (or forecast to be imported), from the grid to supply customers (in aggregate) for the year. If this is not greater than zero, then it is the highest amount of net electrical power exported (or forecast to be exported), into the grid from embedded generating units (as seen by the network, in aggregate) for the year. This is also referred to as the peak supply, as seen by the network.
Capacity of Line (Amps)	The line current rating which takes into consideration the type of line, conductor materials, allowable insulation temperature, effect of adjacent lines, allowable temperature rise and ambient conditions. It should be noted that United Energy operates many types of underground cables in its sub-transmission system. The different types of underground cables have varying operating parameters that in turn define their ratings.
% Above Capacity	The percentage by which the forecast maximum demand exceeds the N-1 cyclic rating.
Energy-at-risk	The amount of energy that would not be supplied to load (for import conditions) or curtailed from generation (for export conditions) if a major outage of a transformer or sub-transmission line occurs at the station or sub-transmission loop in that particular year, and no other mitigation action is taken.
Annual hours per year at risk	The number of hours in a year during which the 10^{th} percentile demand forecast exceeds the zone substation N-1 Cyclic Rating or sub-transmission line rating.

C.2. Abbreviations

Common Term	Description
AAC	All Aluminium Conductor
ABC	Aerial Bundled Cable
ABS	Air-Break Switch
A.C.	Alternating Current
ACR	Automatic Circuit Recloser
ACS	Alternative Control Services
ACSR	Aluminium Conductor Steel Reinforced
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
AFAP	As Far As Practicable
AMI	Advanced Metering Infrastructure
Amps (or A)	Amperes
AMP	Asset Management Plan
AMS	Asset Management System
ARENA	Australian Renewable Energy Agency
ASD	Australian Signals Directorate
BA	Boric Acid
BESS	Battery Energy Storage System
COWP	Capex / Opex Works Program
DAPR	Distribution Annual Planning Report
D.C.	Direct Current
DER	Distributed Energy Resources
DLA	Dielectric Loss Angle
DGA	Dissolved Gas Analysis
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DMS	Distribution Management System
DNSP	Distribution Network Service Provider

DOE	Dynamic Operating Envelopes
DSE	Demand Side Engagement
DSO	Distribution System Operator
DVMS	Dynamic Voltage Management System
EDO	Expulsion Drop Out
EG	Embedded Generation
EMS	Environment Management System
ENA	Energy Networks Australia
ESC	Essential Services Commission of Victoria
ESMS	Electricity (Network) Safety Management System
ESV	Energy Safe Victoria
EUE	Expected Unserved Energy
EV	Electric Vehicle
FMECA	Failure Mode, Effects and Criticality Analysis
FPAR	Final Project Assessment Report
GIS	Geospatial Information System
HV	High Voltage
INMS	Integrated Network Management System
IT	Information Technology
kV	Kilo Volt (Voltage)
LV	Low Voltage
MAIFIe	Momentary Average Interruption Frequency Index event
MDP	Meter Data Provider
MoU	Memorandum of Understanding
MPLS	Multi-Protocol Label Switching
MS	Microsoft®
MV	Medium Voltage
MW	Mega Watt (Active Power)
MWh	Mega Watt hour (Active Energy)
MVA	Mega Volt Ampere (Apparent Power)
NEM	National Electricity Market
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research

NIST	National Institute of Standards and Technology
NOM	Network Opportunity Maps
NST	Neutral and Supply Testing
OHSMS	Occupational Health and Safety Management System
OLTC	On-Load Tap Changer
OMS	Outage Management Systems
OT	Operation Technology
PD	Partial Discharge
PF	Powder Filled
PoE	Probability of Exceedance
PoU	Probability of Under-reach
PV	Photovoltaic
RCGS	Remote Control Gas-insulated Switch
RCM	Reliability-Centred Maintenance
REFCL	Rapid Earth Fault Current Limiter
RIN	Regulatory Information Notice
RIT	Regulatory Investment Test (-D for Distribution, -T for Transmission)
RMU	Ring Main Unit
SAMP	Strategic Asset Management Plan
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SFRA	Sweep Frequency Response Analysis
SOC	Security Operations Capability
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
TCPR	Transmission Connection Planning Report
VCR	Value of Customer Reliability
VEDCoP	Victorian Electricity Distribution Code of Practice
WLWS	Whole-Life Whole-System
XLPE	Cross-Linked PolyEthylene

C.3. Zone substations

Zone substation	Abbreviation	Transformation	Shared supply
Box Hill	BH	66/22 kV	No
Beaumaris	BR	66/11 kV	No
Bentleigh	BT	66/11 kV	No
Bulleen	BU	66/11 kV	No
Burwood	BW	22/11 kV	No
Clarinda	CDA	66/22 kV	No
Caulfield	CFD	66/11 kV	No
Cheltenham	CM	66/11 kV	No
Carrum	CRM	66/22 kV	No
Doncaster	DC	66/22 kV	No
Dromana	DMA	66/22 kV	No
Dandenong	DN	66/22 kV	No
Dandenong South	DSH	66/22 kV	No
Dandenong Valley	DVY	66/22 kV	No
East Burwood	EB	66/22 kV	No
Elsternwick	EL	66/11 kV	No
East Malvern	EM	66/11 kV	No
Elwood	EW	66/11 kV	No
Frankston South	FSH	66/22 kV	No
Frankston	FTN	66/22 kV	No
Glen Waverley	GW	66/22 kV	No
Hastings	HGS	66/22 kV	No
Heatherton	HT	66/22 kV	No
Gardiner	K	66/11 kV	CitiPower
Keysborough	KBH	66/22 kV	No
Lyndale	LD	66/22 kV	No
Langwarrin	LWN	66/22 kV	No
Mentone	M	66/11 kV	No
Mordialloc	MC	66/22 kV	No
Mulgrave	MGE	66/22 kV	No
Moorabbin	MR	66/11 kV	No
Mornington	MTN	66/22 kV	No
North Brighton	NB	66/11 kV	No
Notting Hill	NO	66/22 kV	No

Noble Park	NP	66/22 kV	No
Nunawading	NW	66/22 kV	No
Oakleigh	OAK	66/11 kV	No
Oakleigh East	OE	66/11 kV	No
Ormond	OR	66/11 kV	No
Rosebud	RBD	66/22 kV	No
Surrey Hills	SH	22/6.6 kV	No
Sandringham	SR	66/11 kV	No
Springvale South	SS	66/22 kV	No
Sorrento	STO	66/22 kV	No
Springvale	SV	66/22 kV	No
Springvale West	SVW	66/22 kV	No
West Doncaster	WD	66/11/6.6 kV	CitiPower

C.4. Terminal stations

Terminal station	Abbreviation	Supply voltage	Shared supply
Cranbourne	CBTS	66 kV	AusNet Electricity Services
East Rowville	ERTS	66 kV	AusNet Electricity Services
Frankston	FTS	66 kV	AusNet Electricity Services (switching station)
Heatherton	HTS	66 kV	No
Malvern	MTS	66 kV	No
Malvern	MTS	22 kV	No
Richmond	RTS	66 kV	CitiPower
Ringwood	RWTS	66 kV	AusNet Electricity Services
Ringwood	RWTS	22 kV	AusNet Electricity Services
Springvale	SVTS	66 kV	CitiPower
Templestowe	TSTS	66 kV	AusNet Electricity Services, CitiPower, Jemena
Tyabb	TBTS	66 kV	No