



# Network Planning Guidelines

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Document No. UE GU 2200

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# 1. Approval & Amendment Record

Document No. UE GU 2200 – Network Planning Guidelines – Version 10

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VERSION	DATE	AMENDMENT OVERVIEW
1	November 1997	Original
2	November 1998	Revised – Additional content and updates
3	May 2001	Revised – Additional content and updates
4	October 2009	Revised – Additional content and updates
5	June 2013	Rewritten – Following JAM handback
6	July 2014	Revised – Additional content and updates
7	January 2015	Revised – Additional content and updates
8	July 2016	Revised – Additional content and updates
9	June 2017	Revised - UE Transformation Initiative Outcomes
10	August 2018	Revised - CP/PAL/UE Synergy Recommendations and Rebranding
11	August 2019	Revised – based on the internal audit recommendations

Template Details	Date
EN Standard Document Template Reformatted 1 Aug 2019	01/08/2019

## 2. Introduction

### 2.1 Purpose

The purpose of this document is to establish a uniform and consistent set of guidelines for Network Planning functions at United Energy (UE). This document is intended for use by Network Planning Engineers in their day-to-day activities to prudently plan the UE electricity distribution network and the transmission connection assets that supply UE's network.

The document will need to be updated as standards and planning procedures change over time. It is structured to cover all aspects of Network Planning and is therefore a valuable training document for new Network Planning Engineers. The document is also intended as a quality assurance guide to support UE's regulatory compliance requirements.

### 2.2 UE's Network Planning Objective

Reliable and secure electricity supply is vital for a strong economy and the social wellbeing of the community. UE's network planning activities, being a key component of UE's overall asset management framework, contribute to supporting this outcome for customers supplied within UE's geographic service area.

UE's network planning activities bring value to UE and its customers by maintaining long-term supply reliability of the electricity distribution network (and the transmission connection assets) in response to electricity demand growth, while minimising whole-of-lifecycle capital and operating costs. This planning is undertaken within the context of the regulatory framework set by the National Electricity Rules (NER).

UE's network planning objective is to manage the network performance associated with electrical plant overload in a safe and prudent manner by undertaking strategic network development and risk management planning. This is done through development of least cost, technically appropriate solutions that minimise current and future capital spending for distribution, sub-transmission and transmission connection asset constraints within a fundable budget. This is coupled with preparation and application of detailed contingency plans to manage the risk of loss-of-supply associated with probabilistic planning. UE's approach to uncertainty, through the consideration of options for a full range of future-state scenarios, is an essential component of UE's planning process to ensure solutions to current problems are optimal to meet both current and future requirements.

UE's network planning objective is supported by UE's structured, coordinated network planning process, incorporating sophisticated forecasting and modelling techniques based on sound engineering principles, with resources having the experience to understand the power system as a whole, and the desire to consider and consult on a range of network and non-network options to manage network capacity constraints.

### 2.3 UE's Network Planning Philosophy

UE's method for planning the electricity distribution network for peak demand growth is based on a probabilistic planning approach. It involves the process of selecting (and determining the optimum timing of) technically acceptable options to alleviate identified network capacity constraints based on robust maximum demand forecasts to facilitate customer maximum demand being met with all electrical plant in service.

The planning process involves assessing the risk of loss-of-supply for a critical plant failure, taking into account power system equipment failure rates and repair times using a weighting of 10% (1-in-10 year) and 50% (1-in-2-year) POE maximum demand forecasts<sup>1</sup>. The most economic options that minimise the present-value of the lifecycle cost based on this loss-of-supply risk are selected by UE to accommodate the forecast growth in peak demand.

UE's business investment decisions in augmentations or non-network solutions are based on a least lifecycle cost technically acceptable analysis, considering the Service Target Performance Incentive Scheme (STPIS) and Opex costs. For a market (or customer) analysis, the value of energy-at-risk and electrical losses costs are predominantly used to maximise a Net

<sup>1</sup> This guideline recommends utilising a weighting that aligns with the approach applied by AEMO, and described on page 12 of its publication titled [Victorian Electricity Planning Approach](#), published in June 2016. This weighting is 30% of the expected energy-at-risk using the 10% PoE maximum demand forecast, and 70% of the expected energy-at-risk for the 50% PoE maximum demand forecast when justifying expenditure programmes and projects.

Present Value consistent with the Regulatory Investment Test for Distribution (RIT-D) requirements under Clause 5.17 of the NER. Under a probabilistic planning approach, the optimum timing of investments occur when both the annual value of STPIS and the annual value of expected energy-at-risk exceed the estimated annualised capital costs of augmentation. For this to occur, the maximum demand needs to exceed the (N-1) network capability, and in some cases, exceed the (N) capability.

In order to determine the “economically optimum” level of investment, it is necessary to place a value on supply reliability from the customers’ perspective. It is recognised that this value may depend on the customers involved (and the duration of the outage) and estimating such a value is inherently difficult. It is common practice by many utilities in the world to use an average marginal value of reliability, referred to as the Value of Customer Reliability (VCR). The VCR used by UE is based on a re-weighting of the survey values provided by AEMO. AEMO’s VCR is an updated estimate of the composite (or average) value of customer reliability in Victoria for all electricity customers based on customer surveys. VCR is an important signal for investment and determining reliability levels. In establishing a business case for the approval of investments, location specific VCR values may be used to reflect the different classes of customers served by the network assets. The VCR is a measure of the cost of unserved energy to the customer and is also the basis on which STPIS rates are calculated. The VCR is used as part of the probabilistic planning approach to assess the economic benefits and costs of making investment decisions.

A major consequence of the probabilistic planning approach is a reduced level of network redundancy and system security at times of high demand when assets are highly utilised. To ensure reliability performance obligations can be fulfilled, in developing and augmenting the network, UE aims to maintain risks associated with network capacity at manageable levels. UE achieves this by undertaking detailed contingency planning prior to the summer season of high demand. The purpose of the contingency planning is to reduce the impact of unplanned outages should they occur at times of peak demand. In a network planned in accordance with the probabilistic approach, there are conditions under which the entire demand cannot be supplied with a network element out of service. Contingency plans are therefore developed to restore supply for such events as quickly as possible. As demand and network utilisation increases over time, the efficacy of contingency plans in terms of managing network risks reduces; at some point triggering investment.

UE’s network planning approach has delivered more cost effective network performance outcomes for UE customers and this has contributed to UE delivering lower cost network charges for its customers relative to other distributors around Australia. UE, by industry benchmarks, has a very highly utilised network at all tiers of the distribution supply chain.

## 3. Planning Constraints

### 3.1 Thermal Ratings

The UE network is planned so that it facilitates the operation of all equipment within their cyclic ratings at all times during system normal conditions (i.e. all plant in service) for a 1-in-10 year weather probability, medium (base) economic growth maximum demand forecast.

Cyclic ratings are greater than continuous ratings in that they take into account the daily cycle of demand from overnight lows to daily highs, then back down to overnight lows. The thermal time constant of plant allows plant operating temperatures to remain within design limits when operating to the cyclic rating due to the cyclic heating up and cooling down of plant.

Generally, assets are loaded below their (N) cyclic ratings to account for loss of a critical item of plant and to allow for the implementation of augmentation works. The level of asset utilisation depends on the risk that is inherently built into the network through the setting of the VCR level. A probabilistic planning approach is taken in the UE network where assets are loaded above the (N-1) cyclic rating before an investment occurs with the timing determined by the time at which the annualised value of the energy-at-risk exceeds the annualised capital cost of the investment with the preferred option being the one that delivers the least lifecycle cost.

Short-term emergency ratings are available for outage of an item of plant for operational purposes. These short-term ratings should be used in conjunction with the expected loading levels to determine the actions for a contingency plan if required.

Under some circumstances it is possible that assets may be at risk of being loaded above the (N) cyclic ratings due to unexpected load growth, hotter temperature conditions or where it is uneconomic to augment the network. Options to off-

load, reconfigure or reduce demand on these assets under these conditions should be investigated to minimise the risk of load shedding.

For operational purposes, HV plant shall not be loaded above 100% of cyclic rating under system normal conditions. Plant may be loaded to its short-term emergency ratings in the event of an unplanned forced outage after which time loading must be reduced to no more than 100% of its cyclic rating. For operational purposes, UE HV assets should not be loaded above the dynamic ratings provided in the [Loadings and Ratings Database](#). Exceptions to this apply if the:

1. overload is due to intermittent load (such as railway load) rather than cyclic load for which 5-minute average load can be applied, or
2. NCC considers the ambient/environmental conditions would allow the asset to be loaded higher without compromising safety or asset life, or
3. rating provided in the NCC Ratings Database is suspected by NCC to be incorrect,
4. current load values reported by SCADA are suspected by NCC to be incorrect, or
5. overload is due to temporary emergency switching operations.

Transfer options, voltage reduction, non-network solutions (demand management or embedded generation), load shedding or other contingency measures should be considered and implemented to bring the demand back to 100% of the cyclic rating as soon as practicable when an overload is known.

Depending on the type of plant, the thermal ratings are particularly sensitive to some conditions mainly ambient temperature, wind velocity and direction, soil resistivity and construction.

### 3.1.1 Ambient Temperature

Historically, plant ratings have been based on an ambient temperature of 35°C in summer. In the late 1990's, this assumption was no longer considered adequate as long term weather data in Melbourne shows an average of 7 days per year when the temperature of 35°C is exceeded and approximately 1 day every one to two years that 40°C is exceeded. UE bases its future demand expenditure on plant ratings at 40°C ambient temperature. This is consistent with many international standards, which suggest that transformers and overhead lines should have their maximum ratings calculated at 40°C. Operationally, UE uses dynamic plant ratings that take into account actual ambient temperatures, taking a linear interpolation between the summer and winter ratings. When winter ratings are to be established, the ambient temperature of 10°C shall be considered.

When calculating the summer rating of underground cables, a ground temperature of 25°C shall be assumed. A 10°C ground temperature shall be assumed for calculating the winter rating.

### 3.1.2 Wind Velocity & Direction

Historically, overhead line ratings have been based on an assumed wind speed of 0.61m/s (2f/s) transverse to the conductor. In the late 1990's UE believed this to be excessively conservative and based on recorded wind speeds in Melbourne for summer high temperature conditions, adopted a rating based on an assumed wind speed of 2m/s transverse to the conductors for sub-transmission lines only. This was reviewed by PB Power and Worley International in 2000 and was deemed to be incorrect as direction of wind on hot summer days is predominantly from north and a large number of sub-transmission lines have northerly running sections. The subsequent review in 2001 of overhead line maps and recent analysis of weather data show that wind speeds of 3m/s with a direction of 15° from conductor axis on hot summer days is the most appropriate assumption for overhead bare conductors in the UE region.

During winter or for zone substation switchyards, wind speeds of 0.61m/s with a direction of 90° to the conductor axis shall be considered.

### 3.1.3 Soil Resistivity

Rating of underground cables is quite sensitive to soil resistivity. Cable ratings were reviewed following soil thermal resistivity tests done in zone substations in April 2000. Based on these tests it was recommended to adopt a single thermal resistivity of 0.9°Cm/W for all zone substations with the exception of SS, STO, RBD and FTN where an average figure of 1.2°Cm/W is recommended. Overall, this parameter alone did not result in major de-rating of the underground cables. The review,

however, revealed a rather significant de-rating due to cables being buried either very close to each other or rather deep (more than 0.6m). A number of 11kV feeder exits were de-rated as a result of this review. The single thermal resistivity of 0.9°Cm/W applies to cable ratings within the zone substation yard only. In all other places a common thermal resistivity of 1.2°Cm/W shall be used.

### 3.1.4 Plant Operating Temperatures

Plants are generally operated to temperatures within their design ratings taking into account expected temperature rise above ambient.

For conductors, the maximum operating design temperature is 100°C for sub-transmission, and 65°C for distribution. For XLPE cables the maximum operating design temperature is 90°C.

Transformer ratings have been based on a maximum allowable transformer Winding Hot Spot Temperature (WHST) of 140°C. A recent review of transformer rating revealed this may no longer be acceptable for older transformers that may have high moisture content and poor insulation conditions. It has been recognised by CIGRE that transformers with high paper insulation moisture content can begin to produce gas bubbles at temperatures below 140°C. As a result, the review recommended using a maximum WHST of 130°C for older transformers (of more than 30 years in age).

## 3.2 Voltage Limits

### 3.2.1 Low Voltage System

UE's LV system consists of 400V phase-to-phase voltages and 230V phase-to-ground voltages. As a standard, all new networks should be constructed with these voltages.

Network Planning Engineers are required to arrange the distribution feeder network so that LV customer voltages can be set at satisfactory levels, within the tapping range of all distribution substations. The acceptable steady state voltage range at LV is currently +10% to -6% of nominal voltage at the customer meter. The Dynamic Voltage Management System (DVMS) applied by UE adjusts zone substation float voltage set-points to maintain LV voltages within this range according to AS 61000.3.100-2011 with normal voltage regulation to V99%.

The following voltage limits shall be considered when planning the voltage limits on an LV system.

Minimum LV voltage at end of LV line
3-phase: no less than 376V (-6.0%) at peak load / minimum generation for 99% of the time
1-phase: no less than 216V (-6.0%) at peak load / minimum generation for 99% of the time

Maximum LV voltage at end of LV line
3-phase: no more than 440V (+10.0%) at peak generation / light load for 99% of the time
1-phase: no more than 253V (+10.0%) at peak generation / light load for 99% of the time

If there are circumstances where customers are supplied voltages outside of the limits above, then localised corrective action should be applied as soon as practicable in accordance with Clause 11 of the Victorian Electricity Distribution Code.

LV set-point voltage guideline at distribution transformer terminals (no-load) <sup>2</sup>
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<sup>2</sup> Refer [UE PB 0046](#) - Distribution Transformer Voltage Set-Points 13<sup>th</sup> August 2014.

Supplying More than One Single Customer: 240V to 245V (415V to 424V, 3-phase)

Supplying One Single Customer: 233V to 238V (404V to 412V, 3-phase)

Where the voltage drop (or rise) along a low voltage feeder is so great that the distribution substation cannot be tapped to an adequate output voltage, the following options should be considered:

- Make LV network open point adjustments;
- Transfer customers at the open point across to the other side of the open point;
- Rebalance load or generation across the phases;
- Reconfigure or reconductor the LV system;
- Install low voltage circuit voltage regulators;
- Install distribution transformers with automatic tap changer.

### 3.2.2 High Voltage System

UE's high voltage system consists of 66kV and 22kV sub-transmission, and 22kV, 11kV and 6.6kV distribution voltages. As a standard, all new networks should be constructed with 66kV sub-transmission and 22kV distribution where economic and practical. Augmentation in existing networks shall have voltages consistent with the adjacent network for the purposes of transfer capability.

Network Planning Engineers are required to arrange the distribution feeder network so that HV customer voltages can be set at satisfactory levels. This range must be within the range specified in the Electricity Distribution Code. The acceptable steady state voltage range at HV is currently  $\pm 6\%$  of nominal voltage at the customer meter for 6.6kV, 11kV or 22kV connections (or  $\pm 10\%$  of nominal voltage for customers in rural areas), or  $\pm 10\%$  of nominal voltage at the customer meter for 66kV.

The default voltage set-point at zone substation and transmission connection assets should be set to consider a certain degree of voltage drop across high voltage lines at peak demand and the range of transformer tapping required for the varying demand and generation conditions.

The following voltage limits shall be considered when planning the voltage limits on an HV system.

Minimum HV phase-to-phase voltage at HV customer connection point
66kV: 59.4kV (-10.0%) at peak load
22kV: 20.7kV (-6.0%) at peak load
11kV: 10.3kV (-6.0%) at peak load
6.6kV: 6.2kV (-6.0%) at peak load

Maximum HV phase-to-phase voltage at HV customer connection point
66kV: 72.6kV (+10.0%) at light load
22kV: 23.3kV (+6.0%) at light load

11kV: 11.7kV (+6.0%) at light load
6.6kV: 7.0kV (+6.0%) at light load

If there are circumstances where customers are supplied voltages outside of the limits specified above, then corrective action should be applied as soon as practicable in accordance with Clause 11 of the Victorian Electricity Distribution Code.

<b>HV phase-to-phase default set-point voltage guideline at the zone substation busbar</b>
66 kV: 66.0kV (+0%) to 67.5kV (+2%)
22 kV: 22.0kV (+0%) to 22.9kV (+4%)
11 kV: 11.0kV (+0%) to 11.7kV (+6%)
6.6 kV: 6.6kV (+0%) to 7.0kV (+6%)

The default voltage set-points at each zone substation are located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/ReactivePowerandVoltageRegulation/Voltage%20Regulation%20Settings>

These are the voltages the zone substations will regulate to in the event the DVMS is switched out of service. DVMS will operate to vary the voltage set-points such that voltages on the LV system are regulated to V99% according to AS 61000.3.100-2011.

Switching of long lines, capacitors and transformers out can cause substantial variations for a few minutes while zone substation transformers tap back the distribution voltages to nominal. This is due to the tap changers configuration only changing one step at a time with a time delay. These voltage variations should not exceed Electricity Distribution Code requirements. Network Planning Engineers should undertake load flow studies to determine the acceptable operating limits of the network based on limiting the voltage deviations under these conditions to Electricity Distribution Code requirements.

Where the voltage drop along a high voltage feeder is so great that the distribution substations cannot be tapped to an adequate output voltage, then the following options should be considered:

- Make feeder open point adjustments;
- Install shunt capacitors along the feeder to improve the profile;
- Install voltage regulators along the feeder to improve the profile;
- Reconductor the feeder.

When making open point changes on the network, the voltage change to customers should be considered before making the transfer. This is usually only an issue when customers are transferred from a long heavily loaded feeder to a short lightly loaded feeder or rural areas.

Changes of default voltage set-point levels on the HV system should trigger a review of voltage set-point levels on the corresponding LV systems.

### 3.3 Fault Level Limits

Limiting fault level ensures plant is maintained within its rupture capabilities for all assets connected on the power system including those within high voltage customer installations. It also ensures step-and-touch potentials associated with earth potential rise are maintained within safe limits for phase-to-ground faults.



Fault levels shall be maintained within the minimum of the i) plant rupture ratings, ii) AEMO Use of System Agreement, or iii) those levels specified in the Victorian Electricity Distribution Code as follows.

Maximum Fault Levels
66kV: 2500MVA (21.9kA)
22kV: 500MVA (13.1kA)
11kV: 350MVA (18.4kA)
6.6kV: 250MVA (21.9kA)
400V: 35MVA (50.0kA)

These fault levels relate to standard ratings to which plant and equipment can be purchased. Failure to observe these fault levels may require expensive switchgear replacement.

The fault levels at each zone substation bus are located in the Fault level Manual [UE MA 2201](#) updated annually and stored by each year in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Manuals/UE%20MA%202201%20Fault%20Level%20Manual>

The fault level will reduce along the distribution feeder with increasing distance from the zone substation and depend on factors such as the type of fault, impedance of the fault, and impedance of the network.

**Under no circumstances shall plant be operated above 100% of the plant fault level rating or the limits specified above.**

Where the fault level is forecast to exceed these values, the following corrective steps can be taken on the network:

- Installation of series reactors;
- Installation of NERs;
- Splitting of buses;
- Installation of high impedance transformers;
- Installation of higher fault breaking switchgear;
- Installation of duplicated open bus tie schemes;
- Taking plant out of service during a parallel switching operation; and
- Operating one transformer as hot standby with auto close scheme.

## Consequences of High Fault Levels

Annealing	The ability of the conductors to carry the fault current without reaching a temperature at which they will anneal i.e. such that the properties of the metal are changed to the point that the metal can become brittle.
Clearance	The raised temperature of the conductor increasing the sag to the extent that the line sags into a subsidiary circuit or object due to excessive conductor temp causing metal expansion and lengthening of the line
Rupture	The ability of the fuses or circuit breakers to rupture or interrupt the fault current successfully
Stress	The high level of mechanical and electrical stress during fault conditions could damage mechanical joints and support structures
Ionised Gas	Ionised gases emanating from a fault may cause a fault on another sub-transmission or distribution circuit on a nearby line as these gases are highly conductive
Step & Touch	Step and touch voltages exceed design limits and increases risk of electrocution for faults involving the earth
Fuse failure	Fuses may candle if fault level is too high, resulting in uncleared short-circuits. EDO fuses are particularly susceptible

When a new zone substation is established in an area where there is existing infrastructure or a new transformer added in parallel, a considerable amount of work may be necessary in reconductoring existing lines to meet the new fault level standards. This is because line and cable sizes need to be suitably selected to withstand fault levels. The fault level capability of a line or cable is dependent on the cross section of the conductor, fault current and its duration. A fault current heats the conductor and the time the conductor has to carry the fault current before a circuit breaker is opened can be appreciable. The conductor therefore has to be of sufficient size to carry this current without its temperature rising to the point at which it will anneal, or sag into a subsidiary circuit. For lines and conductors downstream of fuses, it is only the fuse type and the operating characteristics of the fuse that needs to be considered. For those upstream of fuses, it is the back-up protection characteristic that needs to be considered.

Neutral earth resistors (NERs) may be connected at the transformer star point to earth, therefore increasing the zero sequence resistance and reducing the phase-to-ground fault current considerably. NERs are generally shared between transformers at a zone substation. When installing NERs or REFCL equipment, the phase-to-ground connected equipment such as surge arrestors and voltage transformers need to be checked to withstand full neutral displacement capability.

For zone substations with capacitors with neutrals earthed at zone substations, it is important to note the fault level will rise slightly further out from the zone substation, then begin to decrease as the reactance begins to dominate over capacitance.

Some types of fuses are unable to operate reliably at the fault levels given above. EDO (expulsion drop out) fuses are only capable of interrupting fault currents of 2kA. BA (boric acid) fuses are only capable of interrupting fault currents of 10kA. If fault levels exceed these limits then PF (powder filled) fuses should be used. When making open point changes on the network, the adequacy of the fuse rating should be considered before making the transfer. Kaon Fuse Saver technology also has limited fault level capability.

## 3.4 Annual Capital Budget (ACB)

All capex projects need to be justified economically before any projects can be approved. Only the most economic projects should form part of the AMP works programme to maximise the value from each dollar spent. As there is only ever a finite amount of money that can be funded in the budget, some economically viable projects may have to be deferred. It is therefore important to rank projects as part of an overall portfolio according to their relative costs and benefits. UE has a portfolio management tool (C55) that is operated by the Capex, Opex & Special Projects team. UE Network Planning

Engineers enter the upcoming projects, data associated with these projects such as costs and benefits each year through the Asset Management Planning process. For reinforcement projects, the benefits are calculated using the Expected Energy Not Supplied (EENS) as published in the Distribution Annual Planning Report or in the Strategic Area Plans and the costs are estimated by Service Delivery. The output of the portfolio evaluation tool then forms the Annual Capital Budget (ACB).

For projects that are deferred by the C55 portfolio evaluation tool, the risks of project deferral then need to be managed with the development of contingency plans.

All projects should be listed in the Demand Strategy and Plan [UE PL 2200](#) at least one year (ideally 10 or even 20 years for large projects) in advance before a justification is written so that the projects can be accommodated in the forward budget.

Under some situations, projects may be required due to a changed circumstance, even if not listed in the Demand Strategy and Plan. This could result in a few planned projects being deferred due to budget constraints. This situation should be avoided if possible.

### 3.5 Legislative Framework

Network Planning functions are very prescriptive in regulations. The applicable regulations at present include:

Current Regulations Applying to Network Planning:	
National Electricity Rules	
Electricity Industry Act 2000	Electricity Safety Act 1998
United Energy Distribution Licence	Victorian Electricity Distribution Code

Where there is a discrepancy between regulations and the Planning Guidelines, the regulations will take precedence. The Network Planning Guidelines should be updated at least annually to reflect changes in regulations.

## 4. Planning of Distribution Substations & LV Networks

Distribution Substation and Low Voltage Network Planning strategy is undertaken by the Senior Engineer Network Planning. Capex programmes associated with this planning fall under DSS activity code.

### 4.1 Distribution Substation & LV Circuit Ratings

A distribution substation comprises one or more distribution transformers which convert high voltage to low voltage to supply one or more low voltage circuits. Distribution substations also contain HV and LV fusing and sometimes switching equipment around the transformers.

Present standard distribution transformer nameplate ratings are shown below.

Distribution Transformer Nameplate Ratings					
Pole Top	315 kVA	500 kVA			
Kiosk	315 kVA	500 kVA	1000 kVA	1500 kVA	2000 kVA
Indoor		500 kVA	1000 kVA	1500 kVA	2000 kVA

Present standard LV circuit fuse ratings are shown below. Ratings higher than this are achieved with LV circuit breakers. The UE fusing standard [UE ST 2009](#) provides the allowable combination of fuses and transformer sizes to ensure adequate protection discrimination and sensitivity.

LV Circuit Fuse Ratings					
250A	315A	400A	630A	800A	

Distribution substation nameplate ratings are stored in SAP and are accessible via AMFM-GIS. The cyclic ratings are calculated by the Network Load Management (NLM) system using the nameplate rating of the transformers and their type, daily load profile and operating environment.

Whilst distribution substations are not assigned short-time emergency overload ratings, it is recommended that UE's population of distribution substations not exceed 120% of their cyclic rating on a regularly recurring basis. This is used as a proxy for a short-time emergency overload rating.

#### 4.1.1 Overhead Conductors

The table below present thermal ratings for the standard LV conductor in the UE network.

Overhead Conductor	Rating
19/3.25 AAC	350A

The summer rating of non-standard existing conductors can be found in the "Distribution Construction Standard Manual Drawing No. UE 18/7055/8".

## 4.1.2 Underground Cables

It is UE's policy that all new residential estates utilise underground cable – Underground Residential Design (URD).

The current construction standard for aluminium xlpe cables used for LV lines is for a maximum operating temperature of 90°C. Summer and winter cable ratings for LV lines in UE's network are assessed based on soil thermal resistivity of 1.2°Cm/W. A ground temperature of 25°C shall be assumed.

The LV circuits shall not exceed 100% of their summer ratings. Underground cables are assigned with cyclic ratings whereas overhead conductors have continuous ratings. The tables below present the thermal ratings of standard LV underground cables.

### Cyclic rating of 4/c 185mm<sup>2</sup> Al xlpe cable

		Number of LV UG cables in trench		
		1	2	3
Cable depth (m)	0.6	315A	285A	265A
	0.8	310A	280A	260A
	1.0	305A	275A	255A
	1.2	300A	270A	250A

### Cyclic rating of 4/c 240mm<sup>2</sup> Al xlpe cable

		Number of LV UG cables in trench		
		1	2	3
Cable depth (m)	0.6	370A	335A	310A
	0.8	365A	330A	305A
	1.0	360A	325A	300A
	1.2	355A	320A	295A

#### 4.1.2.1 Twin LV cables per circuit

Historically, UE has installed twin LV cables (single circuit) from existing kiosk and indoor substations to supply a new development due to unavailability of site for a new substation. Such installations can be considered from existing pole-mount, kiosk or indoor substations if it considered the LCTA connection. However, it should be noted that any new connection that requires a twin cable from a substation installed on a private property should be avoided where possible as it can result in significant future costs should the customer decide to redevelop the site. The following limitations apply for a shared pole-mount substation:

1. Maximum rating of twin cable (per circuit) is limited to 400A per phase for 315kVA transformer and 630A per phase for >=500kVA transformer (i.e. limited by the maximum allowable fuse rating);
2. No more than 2 existing LV circuits.

### 4.1.3 Aerial Bundled Cables

Aerial Bundled Cables (ABC) should be used in heavily treed areas or hazardous bushfire risk areas where there are trees in close proximity to the power lines. The ratings of LV ABC conductor are shown below.

Aerial Bundled Conductor (LV ABC)	Rating
150mm <sup>2</sup> LV ABC	230A

## 4.2 Setting Tap Positions on Distribution Substations

Setting of tap positions on distribution transformers is the responsibility of the Power Quality Engineer.

The regulation of low voltage on distribution transformers is a function of their loading and their impedance and the impedance of the low voltage network. Typical voltage regulation figures for distribution substations would be as high as 6%. URD and street mains are designed for around 6% drop at the end of the mains cable with the service line drop usually assumed to be 1.5%. On the high voltage network, the voltage regulation is dependent on the dead-band on zone substations' OLTCs being 3%, and the HV feeder regulation being 2%.

The Distribution Code requires UE to maintain low voltage customer voltages at 400/230V +10%/-6%; a 16% operating margin. The total regulation requirements uses up this full operating margin.

Zone substations have DVMS implemented which under normal operation regulate LV voltage such that 99% of customers remain at or below the +10% limit in accordance with AS61000.3.100-2011.

Standard three-phase distribution transformers have the following tapping specification:

Distribution Transformer Taps			
<b>22,000V</b>	433/250V	+10% to -5%	2.5% steps
<b>11,000V</b>	433/250V	+10% to -5%	2.5% steps

Other transformer types are used, however these are used for special applications such as single phase, SWER or 6.6kV systems.

The standard for voltage regulation in Australia has already changed from 415V (240V for single phase) to 400V (230V for single phase). However, the voltage at the LV terminals of the majority of the distribution transformers installed on the UE distribution network is currently set based on the previous voltage standard and is too high in many instances.

Moreover, the widespread use of embedded generation particularly solar photovoltaic systems within customer installations has placed new requirements on networks and customer installations as they have to cater for bidirectional power flows and consequently superimpose over-voltages on the supply voltage for some of the time. It means the highest voltage in the LV systems could (in some cases) be towards the end of the LV feeder and a need to bias the tapping range on the distribution transformer from a voltage boost to a more balanced voltage tap range is now necessary.

Furthermore, UE has implemented wide-scale power factor correction of its feeders using pole-top capacitors. This has significantly reduced the voltage drop along the feeders and has tended to raise voltages within the LV networks by approximately 1 to 4V on power factor corrected feeders.

These increases have been offset for by lowering the zone substation default voltage set-points with DVMS compensating to operating zone substation float voltages at lower levels. Nevertheless there is still a need to continue to adjust some distribution substation taps to optimise voltage profiles.

By taking into account the standard voltage change, power factor correction and solar PV penetration, the 433V standard ratio set on most of the UE distribution transformers was too high and no longer applicable. As a result, the voltage set-

points for distribution transformers are reduced in order to comply with the regulatory limits which are defined in the Victorian Electricity Distribution Code.

Therefore the voltage set-points for distribution transformers which have already been installed or are planned to be installed on the UE distribution network in future are shown below.

Setting Distribution Transformer Taps	No Load Voltage at Transformer Terminals	
Supplying More than One Single Customer	240V – 245V	415V – 425V
Supplying One Single Customer	233V – 238V	404V – 412V

It should be noted that steady state voltage levels are ultimately determined both by individual customer demands, network impedances, and the interaction of tap changers on zone substation transformers. Since each customer's demand varies over time, steady state voltage levels are also varying over time. By having considered the above voltage set-points, the Service Providers shall still ensure that appropriate voltage drop calculations are undertaken to facilitate voltages at the end of the LV circuits remaining within the Code limits all the time.

### 4.3 Distribution Substation & LV Network Reinforcement

Since the heatwave summers of 2008/09, 2013/14 and 2017/18, electrical overload of distribution transformers has been identified as a significant asset management issue. The load over time has become increasingly temperature dependent and more difficult to forecast particularly on the LV network as electrical equipment such as air conditioners have become more readily affordable and are now considered as standard household appliances. This has led to a number of localised street overloads caused by increased loads using up any spare capacity. An overloaded transformer can result in shortening the transformer life substantially, resulting in costly electrical failures in unpredictable times.

UE undertakes the Distribution System Augmentation programme (DSS) to address the fuse operations reported during summer period and to address the substations with utilisations above 120%<sup>3</sup> of the cyclic rating where economic. The distribution substation utilisation is determined based on the aggregated half-hourly energy usage data from smart meters at the LV circuit and substation level using Network Load Management (NLM) which calculates and reports the peak demand on daily and seasonal basis.

With the completion of the smart meters rollout, UE can accurately determine the loading levels in distribution substations and LV circuits through NLM. NLM uses smart meter interval metering information and asset data to determine the actual peak demand. NLM also calculates transformer cyclic ratings based on actual load profiles and this has enabled UE to adopt a fully proactive programme for distribution transformer load management. For LV circuits, UE is using analytics and data capture to identify fuse sizes and phasing information to transition in a proactive programme for the management of LV circuits to supplement the current reactive programme based on observed fuse operations.

#### 4.3.1 DSS Program - Projects Lists

As per [UE PL 2201](#), UE annually issues three lists of distribution substations and LV circuits for the Service Provider to attend:

- P1 - sites with actual fuse operation occurrences of 3 or more and/or peak utilisation greater than 160% of cyclic rating during recent summer. The Service Providers are required to complete the P1 work typically before 31<sup>st</sup> October
- P2 - sites with actual fuse operation occurrences equal to 2 and/or peak utilisation greater than 140% of cyclic rating during the recent summer. The Service Providers are required to complete the P2 typically before 30<sup>th</sup> November

<sup>3</sup> 120% of cyclic rating is considered to be a short-term emergency overload rating

- P3 - sites with actual fuse operation occurrences equal to 1 and/or peak utilisation greater than 120% of cyclic rating during the recent summer. The Service Providers are required to complete the P2 typically before 25<sup>th</sup> January.

A copy of the DSS Planning Strategy can be found below: -

<http://uenetwork.domain.prd.int/PublishedDocuments/PlantBulletins/UE%20PB%200046%20Distribution%20Transformer%20Voltage%20Set-Points.pdf>

### 4.3.2 DSS Distribution Requirements

UE defines the augmentation options for every single project through a document called UE Scope of Work. UE has recently internalised a design resource to investigate the constraint into every identified site and nominate effective augmentation options. The Service Provider will then perform site inspection and line surveys to verify the proposed scope of work. Some of the recommended design practices for distribution substation augmentation include but not limited to the following:

- The distribution substation and LV network should be sized to accommodate the ultimate number of connected customers, length of LV circuits, protection limits as well as voltage and thermal limits (refer to [UE PB 0028](#)).
- Size overloaded transformers so expected peak demand (kVA) does not exceed 120% of name plate rating. However, the Service Provider is required to identify if there is going to be new development in the area and that the recommended size of the new transformer will accommodate for the new development.
- Recommended number of customers per LV Circuit is approximately 50, subject to acceptable voltage drop profile across the circuit, circuit peak demand, circuit fuse size, protection reach at LV feeder extremity, and acceptable selection of the circuit conductor size and type.
- The distribution substation location and LV circuit configuration selection should evenly distribute customer peak demand across all LV circuits aiming to optimise voltage drop and length of the LV circuit.
- The sizing of a distribution substation in case of a new installation or an upgrade of an existing distribution substation should take into account the existing HV Switch Zone placement requirements. It is recommended to consider additional HV Switches, if the HV Switch Zone placement requirement is exceeded.
- Consider building a second substation as opposed to a straight upgrade, or a combination of both; subject to proposed utilisation factors.
- Pole Type Transformers sizes to be installed are 315kVA or 500kVA only. Kiosk Type Transformers size to be installed are 500kVA or 1MVA or 1.5MVA or 2MVA (RMU or IFT).
- Where an additional substation is required, aim to off load neighbouring highly loaded substation(s) which includes optimisation of load where possible within the LV circuit capacity limitations (fuse size & voltage drop & protection reach).
- Where a load test is required to verify adjacent substation loading(s), the results shall be provided to UE for assessment. (Arrange for Load Test prior to loading neighbouring substations).
- Volt Drop calculations required using UE LV Volt Drop (Ver3.0) tool. This may affect the design/positioning of new substations if required.
- Voltage drop on LV circuits is limited to no more than 6% of system normal voltage. However voltage drop of up to 7% can be accepted if it eradicates the need for major works.
- The dashboard for phasing analytics should be checked to see how the existing demand is distributed across different phases. Rebalancing of loads on relevant circuits as per instructions from UE's new load balancing tool, which is currently being developed.
- It is desirable to integrate rectification of any outstanding HV clearance issue at the pole mounted distribution substation together with the augmentation works required by this project where the pole mounted distribution substation is earmarked for upgrade.



### 4.3.3 After Diversity Maximum Demand (ADMD)

The ADMD is the maximum demand per customer taking into account diversity between customers and customer type. It is calculated using the weather adjusted actual maximum demand on the distribution substation and then dividing by the number of customers on the distribution substation.

#### 4.3.3.1 ADMD for residential customers

UE has developed a tool to calculate the ADMD per residential customer and the total load for a new residential development. The tool provides demand figures for low, medium and high density developments depending on its location (by considering affluence of consumers within each suburb). The figures derived from the tool then shall be used to determine the initial demand requirements.

This new tool is available via:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Models/Excel%20Models/ADMD%20Tool.xlsm>

The ADMD adopted in the tool is based on the residential ADMD actuals which are calculated on an annual basis by the Principal Engineer Network Planning. This assessment provides a holistic view of the residential demand on the UE Network. The findings are documented in [UE PR 2207](#) and stored in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Procedures/UE PR 2207 After Diversity Maximum Demand Procedure>

It has come to light that in some cases, the customer's AS3000 submission tend to be over-estimated particularly for high energy consuming appliances such as air-conditioning units, instantaneous electric hot water systems. UE has investigated those appliances, and has found the following diversity should be applied based on the 'capacity of the units'. These diversity figures can then be used to resolve any discrepancies with the customers.

Appliance	Input current	Diversity
Air-condition units	<ul style="list-style-type: none"> <li>30% of the cooling capacity</li> </ul>	<ul style="list-style-type: none"> <li>A large compressor unit (i.e. 10 kW) can supply multiple indoor units</li> <li>75% connected load per unit</li> </ul>
Instantaneous electric hot water system	<ul style="list-style-type: none"> <li>Provided by customer</li> </ul>	<ul style="list-style-type: none"> <li>1 dwelling: ~ 33% connected load</li> <li>1-20 dwellings: ~ 22% connected load</li> <li>20+ dwellings: ~ 15% connected load</li> </ul>
Electric cooktop appliance	<ul style="list-style-type: none"> <li>Provided by customer</li> </ul>	<ul style="list-style-type: none"> <li>1 dwelling: ~ 50% connected load</li> <li>1-20 dwellings: ~ 15% connected load</li> <li>20+ dwellings: ~ 9% connected load</li> </ul>

#### 4.3.3.2 ADMD for industrial and commercial customers

The principles of ADMD typically do not apply for commercial and industrial connections given their unique operations and relatively small numbers of customers.

For industrial development, the “**Underground Industrial Distribution Application Guidelines (UE GU 2402)**” should be used which is available via:

<http://uenetwork.domain.prd.int/PublishedDocuments/Guides/UE-GU-2402%20Underground%20Industrial%20Subdivision%20Application%20Guidelines.pdf>

For commercial developments, typical loadings on similar installations can be used to estimate the expected demand. Typical loading levels of some common commercial applications are outlined below:

- Large Restaurants (e.g. McDonalds) 100-150 kVA

- Supermarkets 350-500 kVA
- Retail warehouse (e.g. Bunnings) 350-500 kVA
- Bistro / Café / Restaurants: 150 – 200 VA per m<sup>2</sup>
- Office Blocks 50 – 100 VA per m<sup>2</sup>

Although the above is an indication of the expected demands, it does not provide indicative expected demands for the types of connection being received (i.e. hotels, gymnasium, childcare, high-rise buildings with multiple retail / commercial applications, EV charging points etc.) Moreover, the consultants are now providing demand allocations based on area.

To assist the Service Provider's Planners, UE is now developing a commercial ADMD tool based on area. Until a combined ADMD tool is published (i.e. residential + commercial) the above indicative loads and existing diversification factors shall be adopted.

#### 4.3.4 Least Cost Technically Acceptable (LCTA)

Planning the development or upgrade of distribution substations and the LV network should be done based on a Least Cost Technically Acceptable (LCTA) approach to satisfy regulatory requirements. For DSS, a Project Application Sheet (PAS) is adequate for individual project approvals for distribution substation and LV network augmentation, once the business cases for overall DSS expenditure is approved.

For CIC works, LCTA connections are defined as below:

- Supply less than 100 Amps - Pole to Pit connection (16mm<sup>2</sup> underground service is considered as the LCTA).
- Supply more than 100 Amps but less than 160 Amps - Pole to Pit connection (50mm<sup>2</sup> underground service is considered as the LCTA connection).
- Supply more than 160 Amps - LCTA connection is to be determined by the Project Planner.

A new substation on customer's property (or road reserve) shall be considered if it is LCTA to do so. Alternative options outlined below should be considered when determining the LCTA connection.

Supply Requirement	Connection method	Assessment	Outcome	Solutions to be considered when selecting LCTA
Supply less than 100 Amps	Connect to existing LV circuit (Pole to Pit Connection)	N/A	N/A	<ul style="list-style-type: none"> <li>• N/A</li> </ul>
Supply more than 100 Amps but less than 160 Amps	Connect to existing LV circuit (Pole to Pit Connection)	Voltage assessment (with new load)	Compliant Voltage	<ul style="list-style-type: none"> <li>• Do Nothing</li> </ul>
	Dedicated LV Circuit from existing transformer		Non-compliant voltage	<ul style="list-style-type: none"> <li>• Adjust transformer tap position</li> <li>• Transfer load to adjacent LV circuit</li> <li>• Reconnector LV circuit</li> <li>• Install new LV circuit</li> <li>• Install new distribution transformer</li> </ul>
	Dedicated LV circuit from a new distribution	Capacity assessment (with new load)	MD < 120% transformer cyclic rating	<ul style="list-style-type: none"> <li>• Do Nothing</li> </ul>

	transformer external to the property		MD > 120% transformer cyclic rating	<ul style="list-style-type: none"> <li>Transfer load to adjacent LV circuit</li> <li>Upgrade existing distribution transformer</li> <li>Install new distribution transformer external to the property</li> </ul>
			MD > 100% LV circuit rating	<ul style="list-style-type: none"> <li>Transfer load to adjacent LV circuit</li> <li>Reconductor existing LV circuit</li> <li>New LV circuit</li> </ul>
<b>Supply more than 160 Amps</b>	Dedicated LV Circuit from existing distribution transformer	Voltage assessment (with new load)	Compliant Voltage	<ul style="list-style-type: none"> <li>Do Nothing</li> </ul>
			Non-compliant voltage	<ul style="list-style-type: none"> <li>Adjust transformer tap position</li> <li>Install new distribution transformer</li> </ul>
	Dedicated LV Circuit (2 per phase) from existing distribution transformer	Capacity assessment (with new load)	MD < 120% transformer cyclic rating	<ul style="list-style-type: none"> <li>Do Nothing</li> </ul>
	Dedicated LV Circuit(s) from new distribution transformer external to property		MD > 120% transformer cyclic rating	<ul style="list-style-type: none"> <li>Transfer load to adjacent LV circuit</li> <li>Upgrade existing distribution transformer</li> <li>Install new distribution transformer</li> </ul>
	New distribution transformer on customers' property		MD > 100% LV circuit rating of one cable	<ul style="list-style-type: none"> <li>Run 2 cables per phase (where technically feasible) from existing distribution transformer</li> <li>Run 2 cables per phase from new distribution transformer</li> <li>Install new distribution transformer on customer property</li> </ul>

For all customer requested works over and above LCTA connection, the customer is required to contribute 100% of the cost. Where a substation is installed on customer's property (i.e. an indoor substation), spare LV conduits shall be installed from the basement to the road frontage. Should the proposed development be of multi-storey building, it may be necessary to create a street circuit. The need for a street circuit should be evaluated at the time of the connection to cater for emergency services such as lifts that are not provided by the customer through backup supplies such as UPS etc.

#### 4.3.4.1 LCTA in Underground Residential Design (URD)

The LCTA low-voltage connection for a residential subdivision shall be underground reticulation. The LCTA high-voltage connection for a residential subdivision shall be overhead reticulation and the distribution substation shall be pole-mounted unless otherwise stipulated by the local Municipal Councils.

As estimates / quotes are based on a total underground design, 10% of the total underground reticulation cost (excluding Public Lighting) shall be considered as the difference between LCTA and Actual.

For Body Corporate developments, the LCTA shall either be a LV supply to the property boundary (customer pillar), or a HV supply to a substation, as applicable.

#### 4.3.4.2 LCTA for Business Customers

The LCTA low-voltage and/or high-voltage connections for a business development shall be overhead reticulation, and high-voltage connection shall be overhead unless:

- There is already existing underground reticulation
- When a substation is required at a school, it shall be either a kiosk or indoor
- Where UE deems that the normal method of connection is not appropriate for a particular area. For instance, a kiosk or indoor substation may be nominated as the LCTA design by UE for an area that is purely commercial or industrial.

#### 4.3.5 Volt Drop

Volt drop and rise calculations are required to ensure customers are delivered voltages within regulatory limits.

Voltage drop on LV circuits is limited to no more than 6% of system normal voltage. However voltage drop of up to 7% can be accepted if it eradicates the need for major works.

Voltage drop should also consider the prevalence of solar PV (or embedded generation) which has the potential to increase network voltages particularly toward the end of LV circuits.

Underground LV circuits generally have a lower voltage drop (flatter voltage profile) than open wire overhead circuits because of the lower line reactance.

If voltage levels are consistently high or consistently low, then consideration should be made to adjusting the distribution transformer tap setting. If voltage levels are consistently high and low, then consideration should be made to reconfiguring the LV system or installing low voltage regulation equipment.

Voltage drop calculations shall be undertaken using the LV Drop tool available via the Citrix Platform.

#### 4.3.6 Transformer Selection

Where constraints identified are associated with the distribution transformer capacity, then consideration should be given to upgrading the transformer capacity or installing a new distribution transformer. The transformer size should be selected on the basis of the load being no greater than 120% of the cyclic rating using the ultimate number of customers and the ADMD from the standard selection of transformers.

The location of a new distribution transformer should take into consideration, the ability to reconfigure the LV network, the availability of an HV feeder for connecting the distribution transformer and the physical and aesthetic constraints in the street.

#### 4.3.7 LV Circuits

LV circuit fuse size should be selected from the standard fuses mentioned in the UE fusing standard [UE ST 2009](#). The fuse size will depend on i) the ultimate peak loading on each phase of the circuit (based on number of customers and ADMD of the suburb); and ii) the fault level impacting the LV protection reach determined by the distribution transformer size, type of circuit conductor, and the length of the circuit.

The recommended maximum number of customers per LV circuit is approximately 50 with customer numbers uniformly distributed across LV circuits wherever possible.

Customer load should be balanced across phases to minimise the amount of negative sequence current and steady state voltage variation on the network at the time of peak demand. If there is considerable unbalance in the existing LV circuit at the time of peak demand (as determined by UE's new phase analytics dashboard and load balancing tool), then rebalancing of the circuit should be considered as part of the LCTA solution.

If there are LV circuit voltage or overload constraints, then consideration should be given to installing additional LV circuits to offload existing circuits on the distribution substation.

Reconductoring LV circuits may be required if it is the LCTA solution over a new LV circuit or new distribution substation.

### 4.3.8 LV Open Points

LV open points are determined by the Senior Engineer Network Planning. They are positioned to be able to carry the maximum demand on the LV circuit and to ensure customers receive voltages within regulatory limits.

For operational safety purposes, it is required to position overhead LV open points at the pole location of any remote controlled switch or automatic circuit recloser.

LV parallels shall not be left permanently on the network as these are likely to result in fuse-blows under high network loading.

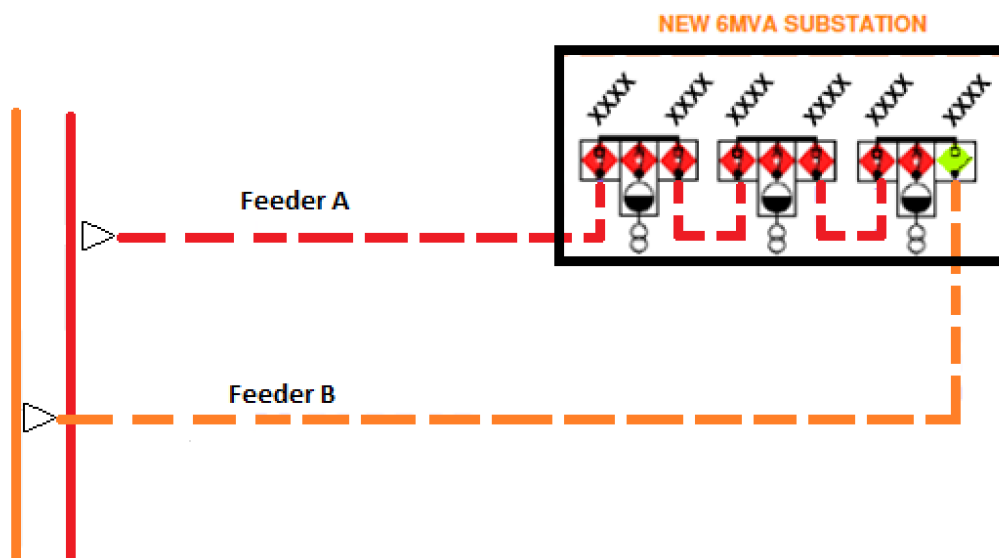
## 4.4 High-rise building supply connection requirements

In recent times, UE has received a number of connections to supply 30-storey high-rise developments. The preferred connection arrangement is to supply high-rise developments using one HV feeder in a loop-through arrangement, with distribution substations installed in the basement. A second HV feeder could be accommodated provided:

- The cost of establishing two feeder connection is only marginally more than the cost of establishing one feeder connection.
- The customer has requested a second feeder.
- There is insufficient capacity on one feeder to supply the total load at site. In this case, the site load can be shared between two feeders provided it is the LCTA solution (i.e. cheaper than increasing capacity on one feeder). Customer engagement should be undertaken earlier in the connection process as some essential services may need to be duplicated.

New developments are incorporating backup supplies to cater for emergency conditions. Where redundancy is not available, a street circuit can be provided for this site (*for a single HV feeder connection only*). The proposed arrangement would provide compliant low-voltage for all customers serviced from this high-rise development. As part of this connection however, a voltage drop calculation should be sought from the developer.

An example of a high-rise connection arrangement is shown below.



Developments higher than 30-storeys are not envisaged on the UE Network. CitiPower has indicated that a dry type solution is considered only when the developments are in excess of 50-storeys. Such solution can be very expensive with the customers opting for the traditional connections mentioned above and implementing solutions to mitigate potential low-voltage issues. Should such developments arise on the UE Network, early engagement with the developer and consultant should be undertaken to identify the least cost that provides safe and reliable supply.

## 5. Planning of Distribution Feeders

Distribution Feeder Network Planning is undertaken by the Principal Engineer Network Planning. Capex programmes associated with this planning fall under the SAP DS(A) activity code or the DL(A) activity code for line capacitors.

A distribution feeder is an HV radial circuit that transports power from the zone substation to the distribution substations and HV customers on the network. Distribution feeders are operated at 22kV, 11kV and in some legacy cases, 6.6kV. Normally Open switches (either manual or remote controlled) are connected between feeders to allow for load transfers from one feeder to another.

### 5.1 Feeder Ratings

Feeder ratings are specified in Amperes. Feeder ratings (typically in the range of 250A to 400A) are generally limited thermally by the overhead line or underground cable sections on the main backbone because the backbone carries the majority of the feeder's current. Feeder circuit breakers generally have a much higher duty (typically 400A or 630A) and therefore are unlikely to be the limiting factor in the overall feeder rating, although low CT ratios or low protection min-ops can sometimes limit the rating. Switches on the distribution feeders are generally limited to 400A.

In assigning a rating to a feeder, both summer and winter ratings are required with winter ratings being higher than summer ratings because of the cooler ambient conditions. The whole feeder backbone should be inspected for the type of conductor and its construction type using UE's AMFM-GIS/Network Viewer before a rating is assigned and the distribution of substation loads down the feeder taken into account using meter aggregation data from NLM. Any uncertainty in the rating or the conductor details should be checked with Primary Assets first, and then if required confirmed with a survey of the feeder. Most likely the limiting item will be close to the zone substation where the current is greatest.

In certain circumstances the feeder capability may be limited by voltage drop which can be confirmed using load flow simulation in AMFM-GIS. For these feeders, the voltage limitation should be represented by reducing the rating of the feeder to the current level that creates the voltage limitation.

#### 5.1.1 Overhead Conductors

The present construction standard for aluminium overhead lines used for HV feeders is for a maximum operating temperature of 65°C with a circuit-to-circuit differential of 30°C. Many older lines were built to 50°C maximum or 25°C circuit to circuit differential.

Presently all new designs for overhead high voltage lines are carried out for a maximum operating temperature of 65°C and a 30°C temperature differential (40°C/10°C), i.e.; top circuit operating at 40°C and bottom circuit operating at 10°C. In rare cases, distribution aluminium conductors can be designed to operate up to 80°C if specifically requested for new feeders or if uprating is required for existing feeders that have become more heavily utilised. However, in such cases the temperature differential would be different. For sections up-rated in urban areas where the span lengths are generally short it has been found that very little construction work is required to achieve the up-rating with a 30°C differential.

The rating of 19/3.25AAC lines built to the standard 65°C /30°C would be rated for 350A summer and 395A winter. By comparison, 6/.186ACSR lines will need to be designed for 80°C /35°C to obtain the same summer rating.

Whilst the most common limitation in overhead line rating is the clearance, underground cables are limited in terms of the loss-of-life of the cable insulation because of temperature rise. Operating the cable at excessive temperatures will result in accelerated deterioration of the insulation and potential failure.

Summer and winter conductor ratings for HV feeders in UE's network are assessed based on the following assumptions:

	WINTER	SUMMER
Ambient temperature	10°C	40°C
Operating temperature	65°C	65°C
Circuit to circuit differential	30°C	30°C
Wind speed	0.61 m/s	3 m/s
Angle of wind to conductors	90°	15°
Time (day or night)	Day	Day
Environment (outdoor or indoor)	Outdoors	Outdoors
Direct solar radiation	1000 W/m <sup>2</sup>	1000 W/m <sup>2</sup>
Diffuse solar radiation	100 W/m <sup>2</sup>	100 W/m <sup>2</sup>
Conductor surface	Rural Weathered (Normal)	Rural Weathered (Normal)
Emissivity of Conductor – Rural Weathered	0.5	0.5
Ground reflectance (albedo)	0.2	0.2

The maximum design temperatures vary with the type of conductors and the voltage as shown below:

Voltage	Maximum design temperature
66 kV	100°C
LV to 22 kV	50°C for SC/GZ conductor
LV to 22 kV	65°C for AAC & ACSR conductor
LV to 22 kV	75°C for HVABC & LVABC

The “Overhead Line Current Ratings” excel model should be used for calculating the overhead line ratings. This rating tool is based on ESAA D(b)5-1988: Current Rating of Bare Overhead Line Conductors Guidelines.

The model for overhead high voltage feeder line rating calculation is located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Ratings/Plant%20Ratings/Overhead%20Lines/Overhead%20Line%20Current%20Ratings%20Calculator.xls>

The table below present summer and winter thermal ratings for the most commonly used conductors in UE network based on UE’s standard construction.

Overhead Conductor	Summer Rating	Winter Rating
19/4.75 AAC	585A	635A
19/3.75 AAC	425A	475A
<b>19/3.25 AAC</b>	<b>350A</b>	<b>395A</b>
7/4.75 AAC	300A	340A
6/.186 7/.062 ACSR	265A	295A
19/.083 Cu	265A	285A
7/.104 Cu	190A	205A
7/3.00 AAC	175A	190A
7/.080 Cu	140A	145A
6/1/.093 ACSR	115A	125A

### 5.1.2 Underground Cables

The current construction standard for aluminium and copper xlpe cables used for HV feeders is for a maximum operating temperature of 90°C. Summer and winter cable ratings for HV feeders external to the zone substation yard in UE's network are assessed based on soil thermal resistivity of 1.2°Cm/W.

Tables below present summer and winter thermal ratings for the most commonly used cables in UE's network based on UE's standard construction.

Underground Conductor (in duct)	Summer Rating	Winter Rating
3/c 35mm <sup>2</sup> Al xlpe 22kV axhc	130A	145A
3/c 185mm <sup>2</sup> Al xlpe 22kV axhc	315A	355A
<b>3/c 240mm<sup>2</sup> Al xlpe 22kV axhc</b>	<b>365A</b>	<b>410A</b>
3/c 240mm <sup>2</sup> Cu xlpe 22kV cxhc	480A	<b>535A</b>
1/c 630mm <sup>2</sup> Cu xlpe 22kV cxhc	775A	880A
3/c 127mm <sup>2</sup> (0.2in <sup>2</sup> ) Cu 22kV hsl	275A	310A
3/c 159mm <sup>2</sup> (0.25in <sup>2</sup> ) Cu 22kV hsl	315A	355A
3/c 127mm <sup>2</sup> (0.2in <sup>2</sup> ) Cu 11kV	260A	295A



Underground Conductor (in duct)	Summer Rating	Winter Rating
3/c 159mm <sup>2</sup> (0.25in <sup>2</sup> ) Cu 11kV	315A	355A
3/c 185mm <sup>2</sup> Cu 11kV plysws	335A	375A
3/c 240mm <sup>2</sup> Al 11kV axhc	365A	410A
3/c 300mm <sup>2</sup> Cu 11kV plysws	430A	485A

Underground Conductor (direct buried)	Summer Rating	Winter Rating
3/c 35mm <sup>2</sup> Al xlpe 22kV axhc	160A	
3/c <b>185mm<sup>2</sup> Al xlpe 22kV axhc</b>	385A	
3/c 240mm <sup>2</sup> Al xlpe 22kV axhc	445A	
3/c 240mm <sup>2</sup> Cu xlpe 22kV cxhc	585A	
1/c 630mm <sup>2</sup> Cu xlpe 22kV cxhc	940A	
3/c 127mm <sup>2</sup> (0.2in <sup>2</sup> ) Cu 22kV hsl	305A	345A
3/c 159mm <sup>2</sup> (0.25in <sup>2</sup> ) Cu 22kV hsl	345A	390A
3/c 127mm <sup>2</sup> (0.2in <sup>2</sup> ) Cu 11kV	300A	335A
3/c 159mm <sup>2</sup> (0.25in <sup>2</sup> ) Cu 11kV	345A	385A
3/c 185mm <sup>2</sup> Cu 11kV plysws	390A	440A
3/c 240mm <sup>2</sup> Al 11kV axhc	445A	
3/c 300mm <sup>2</sup> Cu 11kV plysws	500A	560A

The CYMCAP software should be used for calculating underground cable ratings of feeder exit cable due to congestion using the actual load profiles, separation between cables and depth of cables.

### 5.1.3 Aerial Bundled Cables

Aerial Bundled Cables (ABC) should be used in heavily treed areas or hazardous bushfire risk areas where there are trees in close proximity to the power lines. The ratings of HV ABC conductor are shown below. It should be noted that 22kV HV ABC has limited phase-ground fault current capability and can only be used in restricted areas of the network where fault level is low.

Aerial Bundled Conductor (HV ABC)	Summer Rating	Winter Rating
185mm <sup>2</sup> HV ABC	395A	490A
35mm <sup>2</sup> HV ABC	150A	185A

#### 5.1.4 Overall Feeder Rating

The cyclic rating of a feeder is determined by the limiting backbone section. The limiting sections for a given feeder in summer and winter can be different.

If the feeder has dropped significant load wayside before reaching a limiting section, then this load should be added to the rating of the limiting section and the rating of the feeder amended accordingly.

A cable rating is affected by the way it is buried in the earth and the soil resistivity. Generally, an underground cable will be found to have at least one conduit section beneath a vehicle crossover somewhere along the route and therefore the cable will be assigned an in-duct rating rather than its direct buried rating, as the cable capacity is limited by the thermally constrained section, in the duct. The pumping of Bentonite in these ducted sections will achieve a higher rating (if installed without air gaps), although this will make replacement of the cable more expensive in future as it will no longer be able to be withdrawn from the conduit. Bentonite should only be used in limited circumstances.

Sometimes feeder ratings can be limited by protection equipment settings at the zone substation. Generally the feeder rating should be capped to the “maximum safe load”, calculated to be 120% of the winter rating. This is determined by the Protection Engineers.

Generally feeders can be loaded up to 85% utilisation as this a typical trigger point at which many augmentations become economic under probabilistic planning. Additional headroom over and above normal system demand allows part of the load from a faulted feeder to be transferred to adjacent feeders even during peak loading conditions.

Utilisation in terms of distribution feeders uses the instantaneous SCADA Ampere data except in instances where there is traction load (or short time fluctuating loads). In these instances, 5 minute average loading should be used in calculating utilisation.

#### 5.1.5 Overload Ratings

Cables have a one-hour emergency rating which can be utilised during system abnormal conditions. These ratings should not be relied upon for system normal planning. The emergency ratings are typically 1 to 2 MVA above the nominal rating of the cable for 11kV and 22kV systems respectively.

For overhead lines, there are no emergency ratings however dynamic wind ratings may be available for certain weather conditions. As far as the wind velocity is concerned, use of a universal value of 0.61m/s is considered conservative. The line rating should reflect the actual climatic condition (Melbourne weather), the location of the line and the exposure of the line to wind at times of high load. Analysis of the historical data of wind direction and velocity in the metropolitan area of Melbourne shows that on high temperature days (30° C or higher) wind speed and direction is greater than 0.61m/s blowing from north more than 99.38% of the time. Adoption of a dynamic line rating according to wind velocity and direction is innovative and can achieve significant rating increases.

#### 5.1.6 Recording Feeder Ratings

All feeder ratings including a description of the limiting section shall be recorded in the “Loadings and Ratings Database”, which is an Excel spread sheet managed by UE Network Planning. This is the primary source of rating information for feeders and NCC uses it extensively in day to day operation of the network.

The definitive version of the “Loadings and Ratings Database” is located in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Ratings/NCC%20Ratings%20Database/Ratings.xlsm>

The operational version of the “Loadings and Ratings Database” is located in the VAULT.

## 5.2 Standard Conductors

UE now standardises on particular conductors to reduce inventory requirements for conductors and fittings. The standard conductors are listed below.

### 5.2.1 Overhead Conductors

Standard Distribution Overhead Conductors for both 11kV and 22kV:	
19/3.25AAC	(standard)
19/3.75AAC	(jumbo)

The first choice for new sections of line should be 19/3.25AAC. This will generally be required in urban areas and lines likely to carry substantial load. This conductor has a nominal summer rating of 350A. This conductor meets fault level requirements.

For rural areas, or on spurs that are unlikely to become part of a feeder backbone, 7/3.0AAC may be sufficient. The use of this conductor close to a zone substation may require it to be fused as the fault levels and feeder protection times may be such that subsequent to a fault on the line the conductors may sag into a subsidiary circuit or even be damaged. The use of 3/2.75St is generally for use in rural area, in areas of low load growth, and should not be used where loads will exceed 300kVA in the foreseeable future. The losses become substantial after this level with this conductor type.

In some instances 19/3.75AAC may be used where installation of another feeder exit is not possible or uneconomic. Such 'jumbo' feeders will be required in heavy industrial areas or on stations where additional feeder exits are not available.

### 5.2.2 Underground Cables

Standard Distribution Underground Cables for both 11kV and 22kV:	
3/c 240mm <sup>2</sup> Al xlpe axhc	(standard backbone)
3/c 185mm <sup>2</sup> Al xlpe axhc	(standard non-backbone) – only for 22kV <sup>4</sup>
1/c 630mm <sup>2</sup> Cu xlpe cxhc	(jumbo)
3/c 240mm <sup>2</sup> Cu xlpe axhc	(jumbo)

3/c 240mm<sup>2</sup> Al xlpe axhc is used for feeder backbones close to the zone substation, zone substation exits and to supply central business districts or large industrial loads. It is also used where other cables are in close proximity or in duct banks, thus leading to de-rating of the cables. This improves the rating, which would have otherwise been inadequate given thermal de-rating.

3/c 185mm<sup>2</sup> Al xlpe axhc is for general use in feeders for URD or indoor substations. Care should be exercised when designing systems that are in close proximity to zone substations as this cable in a duct will limit the capacity that can be obtained from the up-rated overhead lines.

In some instances 1/c 630mm<sup>2</sup> Cu xlpe cxhc or 3/c 240mm<sup>2</sup> Cu xlpe cxhc may be used where installation of another feeder exit is not possible or uneconomic, or the required rating cannot be achieved. Such 'jumbo' feeders will be required in heavy

<sup>4</sup> For 11kV, the standard stock underground cable is 3/c 240mm<sup>2</sup> Al XLPE.

industrial areas or on stations where additional feeder exits are not available. The rating of the former cable generally utilises the full circuit breaker rating.

### 5.2.3 Insulated Aerial Bundled Conductor

Standard Aerial Bundled Conductor for both 11kV and 22kV:
185mm <sup>2</sup> HV ABC – Feeder backbone segments or inter-feeder tie lines
35mm <sup>2</sup> HV ABC – Fused radial supply applications

HV ABC conductor is more expensive than regular overhead and should only be used in areas where there is a high incidence of feeder faults where all cheaper fault prevention options have been used, or in heavily vegetated areas.

## 5.3 New Feeders

New feeders can potentially bring a substantial improvement in reliability over other feeder augmentation options such as reconductoring, because of the reduced customer numbers on the feeder and the potential lower exposure to faults especially when the existing network can be used to provide much of the new feeder.

Generally a spare circuit breaker needs to exist at the zone substation or a vacancy for a new breaker on an existing bus, for a new feeder to be economic. Where none exist, it is possible to piggy-back two feeders onto the one feeder circuit breaker and install auto-circuit reclosers on each of the two backbones.

New feeders can be justified relatively easily when a transformer is added to a zone substation as such an augmentation usually provides a new bus and new feeder circuit breakers and the failure to install additional feeders may mean the new transformer capacity cannot be properly utilised.

New feeders should always be directed into potential or known growth areas to provide a large step change in capacity to supply growth or in areas that are highly utilised with poor reliability. Open points should be positioned with an aim to meet peak demand, minimise SAIDI and then minimise losses.

If possible, feeders should not be placed on the same poles as other distribution feeders unless congestion of feeders makes this impossible or it is uneconomic to do so. This philosophy reduces the risk of a double contingency as it limits the exposure to a single accident or event to a single feeder.

The exit cable should be as short as possible to avoid congestion around the zone substation and to keep cabling costs down.

Care shall be taken as much as practicable when configuring the feeder network so that adjacent feeders exit from different bus groups to ensure a bus outage would not cause multiple outages to the feeders that supply the same area. This is to enable sufficient load transfer capability and operational flexibility in the event of an emergency. Such approach cannot be adhered to when establishing a new zone substation with a single transformer as only one bus is available. However, zone substations with multiple transformers will provide ample opportunity to interleave the feeder network.

## 5.4 Feeder Reinforcement

### 5.4.1 Thermal Uprating

Some conductors can be uprated if clearances are increased or there is already sufficient clearance between the overhead and any lower circuits or ground (either restringing to a higher tension or reconfiguring the circuits), or additional poles are placed to reduce sag. A survey and design would be required to confirm the technical viability of this option. Typically, the rating of distribution lines is built to the standard 65°C operating temperature. It is possible to thermally uprate a section of conductor up to 80°C operating temperature. Therefore, where a feeder is limited by overhead line ratings, thermal up-rate should be considered as an alternative to more expensive augmentations such as establishing a new feeder.

### 5.4.2 Bentonite

Where a cable is the limiting factor for a feeder and the cable is ducted, the feeder rating can be raised by filling the duct with Bentonite, as this portion of the cable will no longer require thermal de-rating. This improves the heat dissipation from the cable. Where there is no ducted section on the cable, the direct buried rating can be utilised. Bentonite has problems if not installed correctly as air-pockets can form in the filled conduit. Furthermore, replacing the cable in future becomes more difficult and expensive with the cable now permanently attached to the conduit. For these reasons, use of Bentonite should be kept to a minimum except in circumstances where the required rating cannot be achieved by another means.

### 5.4.3 Reconductoring

Reconductoring of feeders involves replacing limiting conductor sections along the feeder with higher rated conductor. Identification of the backbone sections to reconductor is performed using Network Viewer or AMFM-GIS to identify ratings along the length of the feeder and assessing the load distribution using the power system simulator inbuilt in AMFM-GIS. Reconductoring the backbone to standard conductors and standard design temperatures such as 19/3.25AAC 65°C/30°C is the preferred option however other conductors or design temperatures may be required in some instances.

When reconductoring a feeder, transfer capability to adjacent feeders should be considered. Strong transfer capability between zone substations means that utilisations on zone substations and terminal stations can be increased thereby potentially deferring more costly augmentations.

Other alternatives should be considered before proceeding with reconductor works. Alternatives include capacitor placement (only useful if the feeder is not operating close to unity power factor during peak loading), load transfers, embedded generation and demand management alternatives. The decision between various alternatives should be based on financial evaluations using UE's "Investment Evaluation" model.

### 5.4.4 Line Capacitors

An effective feeder augmentation activity is the placement of pole top capacitor banks along a heavily utilised poor power factor feeder. While the rating remains the same, the effective increase in capacity is derived from the reduced reactive power flow in the line, reducing the amount of current drawn through the feeder. The standard pole top capacitor size used in the network is 900kVAr. Further details of line capacitors are provided later in this document.

### 5.4.5 Jumbo Feeders

Jumbo feeders are recommended for feeders with high demand and relatively low customer numbers such as in industrial areas where the standard conductor is unable to supply the demand requirements.

Jumbo feeders are also useful in setting up strong interconnections between zone substations in reinforcing transfer capabilities. Higher transfer capability can allow increased utilisation of assets and hence deferred network augmentation.

Jumbo feeders may also be needed if there is insufficient room left in the zone substation for additional feeder exits.

Jumbo feeders usually use 19/3.75AAC conductor.

Jumbo feeders may be limited in rating by switches and other equipment on the HV feeder. These factors should be considered when determining the rating of a jumbo feeder.

Consideration should also be made to the ability of adjacent feeders to pick up the load of the jumbo feeder in the event of a forced outage. Therefore improved interconnections and some reinforcement of adjacent feeders may be required if a jumbo feeder is established.

### 5.4.6 De-rating Feeders

Occasionally a feeder will have to be de-rated. This may be due to:

- Incorrect rating assigned to feeder initially;
- A high number of faults or age have caused degradation of the feeder;
- Distribution of load changed along the feeder causing a constrained section;

- Feeder was overloaded at some stage causing some degradation;
- Environmental conditions in which the feeder resides have changed; or
- Another cable has been installed in close proximity.

The feeder capability will need to be assessed in such situations to determine whether any corrective action is required to avoid overload and increased likelihood of failure.

#### 5.4.7 Feeders Owned By Other Distribution Businesses

Some of UE's customers are supplied by feeders of other DNSPs. This is generally the case for customers on the fringe of the UE network. Although the preferred option is to connect these customers to the UE network, under some situations it may not be economic to do so due to high capital cost of extending UE feeders or providing new feeders from UE zone substations.

Connection of additional substations to feeders of other DNSPs shall be preceded with a formal request to the Network Planning team of the other DNSP. Under the NER, the DNSP is required to respond to UE with a quotation that is fair and reasonable. This request shall be initiated by the Principal Engineer Network Planning and may be done in response to an enquiry by a Service Provider Project Planner. The Principal Engineer Network Planning shall work with the relevant DNSP to determine the least cost technically acceptable solution applying the respective planning standards of the DNSP to their respective assets owned by the DNSP. Once the costs are provided, the Principal Engineer Network Planning shall assess the cost provided by the other DNSP against the cost of a UE network augmentation to supply the substation. The lowest cost option shall be implemented.

Under no circumstances shall a Service Provider connect a new distribution substation to another DNSP's feeder without prior approval from the Principal Engineer Network Planning.

### 5.5 Switch Zones

Dividing the length of a feeder into isolatable sections improves network reliability by reducing the amount of network that needs to be out of service while repairs or maintenance activities are being made. This means the time off supply following a fault for the bulk of customers on a feeder reduces to the amount of time needed to switch the network to an alternative configuration using the spare capacity of adjacent feeders.

Given a fault condition somewhere along the length of a feeder, the entire feeder can be affected. Switching zones allow for a faulted portion to be disconnected at both ends. Good placement of switches and tie lines allow for supply to be restored around the fault. Doing this allows a faster restoration of power to the majority of customers rather than waiting for repairs to be undertaken. This impacts CAIDI and hence SAIDI, reducing potential STPIS penalties.

Selection of switch zone sizes and placement of tie lines for transfer capability are important planning decisions as they have a significant influence over CAIDI and SAIDI.

Review of switch zone sizes should be undertaken whenever a new distribution substation is added to the network.

#### 5.5.1 Customer Numbers and Types

Distribution feeders are the asset class that provides the greatest contribution to total SAIDI for UE. Hence minimising the exposure of a distribution feeder to faults by protecting the backbone, providing an ability to sectionalise the feeder and minimising the number of customers on a feeder are very important considerations when planning a distribution feeder network.

It is preferable to keep the number of customers per feeder balanced and below 5000 to reduce the impact on SAIDI for feeder faults on any given feeder. ACRs and remote controlled switches should be used to keep the number of customers in a remote controlled switching zone to less than 800 where practical and economically viable to do so.

To maximise utilisation of a feeder, a mix of domestic, industrial or commercial customers on the same feeder is desirable as these customer bases have significantly different load profiles. Combining these customers will vastly improve the load factor on the feeder and therefore the utilisation by spreading out the demand peak over a greater period of time. Sectionalisation of the different customer types using switches is however desirable in such circumstances.

## 5.5.2 Switches and Isolators

A switch is a ganged (i.e. capable of simultaneous interruption of current across all three phases) device that is capable of breaking load current. These devices are used along the length of a HV feeder allowing switching and isolation of a portion of the feeder. Switches are also used as open points for inter-feeder tie-lines. Switches can be manually operated on site, or if fitted with remote control capability, can be operated from the NCC.

Isolators, by comparison, are manually operated and have no designed load breaking capacity although have been found by test and by experience to be capable of breaking very small loads and magnetising currents. For this reason, isolators can only be used when the feeder has actually faulted and is out of service or has no load. An isolator can only be operated a single phase at a time. Isolators cannot be used in open point changes for load transfers, rather they are only used for fault isolation and restoration activities.

All newly installed switches in the UE network are metal hermetically sealed SF6 units. Air-break switch and isolator usage has been discontinued owing to the increased failure rates and maintenance costs from these ageing devices. A programme of replacement is underway, as the decision was made around 10 years ago to no longer maintain, but replace them instead, assigning any faulty devices awaiting replacement with a Caution Regarding Operation (CRO) tag.

Type of switch	Acceptable as safe "point of isolation" in open position	Make & break small current e.g.10-15A (p f >0.7)	Make & break normal load current e.g. 400A (p f >0.7)	Carry fault current e.g. 13.1kA (22KV) & 18.4kA (11KV) for 1 sec	Interrupt fault current e.g. 13.1kA (22KV) & 18.4kA (11KV)
Gas insulated line switch			400 A		ě
Automatable Gas insulated line switch or			400 A		ě
Gas insulated Ring Main type switch					ě
Gas insulated switch fuse Normally with RMU			200 A		ě
Gas insulated Circuit breaker, Normally with RMU			200 A		
Oil insulated on/off type rotary switch					ě
Automatic Circuit Recloser ACR					
Dis-connector, single phase & 3 phase		ě	ě		ě



Some different symbols for varied switch types on the UE network:

#### Isolating Devices

	disconnect (isolator) ganged (Closed)
	disconnect (isolator) unganged (Closed)
	fuse hinged ganged (Closed)
	fuse hinged unganged (Closed)
	fuse not hinged (Closed)
	link (Closed)
	circuit breaker (Closed)
	auto-recloser (Closed)
	auto-sectionaliser (Closed)
	gas insulated (Closed)
	arc chute hinged ganged not enclosed (Closed)
	arc chute hinged ganged enclosed (Closed)
	horn deflector not hinged ganged (Closed)

#### Isolating Devices

	elbow term not bolted (closed)
	elbow term bolted (closed)
	remote control gas switch (closed)
	arc chute hinged unganged (Closed)
	rotary VT in service (closed)
	rotary TT in service (closed)
	transformer unganged not hinged not enclosed in service (Closed)
	transformer ganged not hinged not enclosed in service (Closed)
	gas insulated hinged enclosed in service (Closed)
	arc chute not hinged enclosed in service (Closed)
	transformer (Closed)
	live line clamp (Closed)
	horn deflector not hinged unganged (Closed)

#### Isolating Devices

	bridge (Closed)
	arc chute not hinged ganged (Closed)
	arc chute not hinged unganged (Closed)
	expulsion type interruptor hinged ganged (Closed)
	expulsion type interruptor hinged unganged (Closed)
	expulsion type interruptor not hinged ganged (Closed)
	flicker blade not hinged unganged (Closed)
	flicker blade not hinged ganged (Closed)

**NOTE : Green Diamond on Isolating Device = Open**

### 5.5.3 Switch Placement on Overhead Networks

The following definition are used when defining switch placements:

- Major Switch Zone: Section of line between load break switches,
- Minor Switch Zone: Section of line between load break switches and isolators

Minor switch zones are no longer applicable for UE given UE no longer installs isolators on its network.

#### 5.5.3.1 Urban Areas

Historically UE guidelines specified major switching zones shall have no more than 1000kVA of installed transformer capacity where reasonably possible. This was on the basis that all or most of the customers within a switch zone would be restored using LV parallels during off peak conditions. However, achieving this in many cases was found to be uneconomical, and logistically impractical, considering the substation density in the network. This is especially challenging in HV overhead supply areas. Often, there are no spare poles to accommodate new switches and installing new poles are deemed to be impractical due to urbanisation. Given kiosks and indoor substations are equipped with switches themselves, every such substation has its own switch zone and as a result, switch zone capacity is not an issue in undergrounded areas.

Therefore, the following guideline, shall be used for switch zone capacity in urban areas irrespective of the distribution medium voltage level:

- The total installed transformer capacity within a major switch zone not exceeding 2000kVA; and
- Substations greater than 1000kVA provided with an exclusive switching zone.

Other factors that should be considered include:

- Larger spur circuits should be fitted with a switch or fused switch as close to beginning of the spur as possible;
- Exposure of the line to risks is important, long segments of line (particularly those running alongside freeway and larger roads) need switches even if no distribution substations exist in the switch zone;
- Consider position of switches so that segments of network fed by one feeder can be switched to another feeder from an adjacent zone substation to support transfer capability;
- Provide segregation of industrial, commercial and residential customers on a feeder so as to avoid conflicting requirements for planned interruptions; and
- Number of customers in the switch zone. If more than 600 customers are connected within a switch zone, consider whether it is economically viable to split the switch zone.



### 5.5.3.2 Rural Areas

Customer numbers and load density in rural areas is variable and hence switching zone sizes may vary and need to be specific for the location. As a guideline, each rural area switching zone is to:

- Limit the total installed transformer capacity within a major switch zone to 1000kVA;
- Supply no more than 20 substations;
- Supply no more than 100 customers;
- Not exceed 10km of line in a switching zone (consider reliability benefits); and
- Provide segregation of towns from rural areas on a feeder.

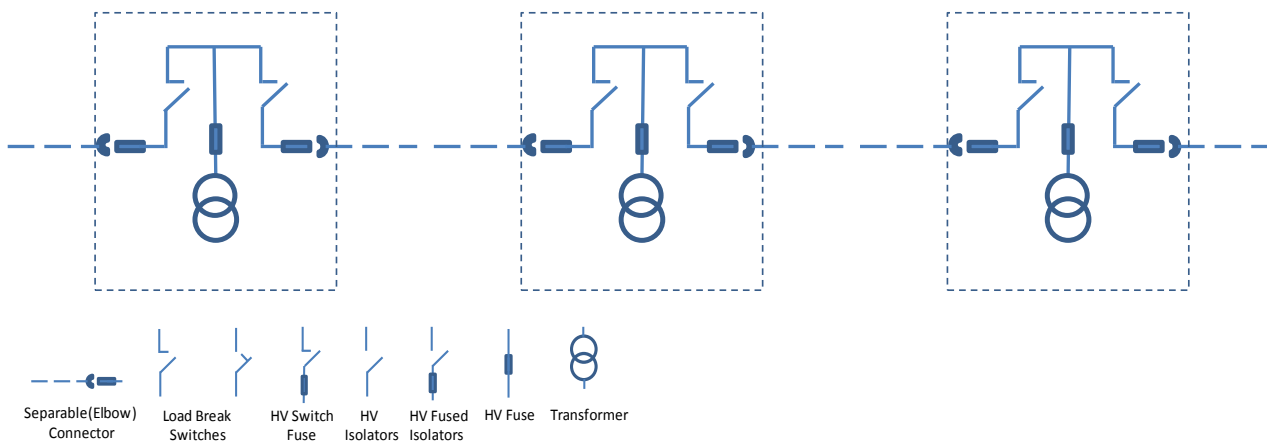
## 5.5.4 Switch Placement on Underground Networks

### 5.5.4.1 Switch Placement

While overhead lines are exposed and much more susceptible to weather events and other physical disturbances, typically faults are easily located and quicker to repair than faults on underground cables which can typically take a number of days to locate and repair.

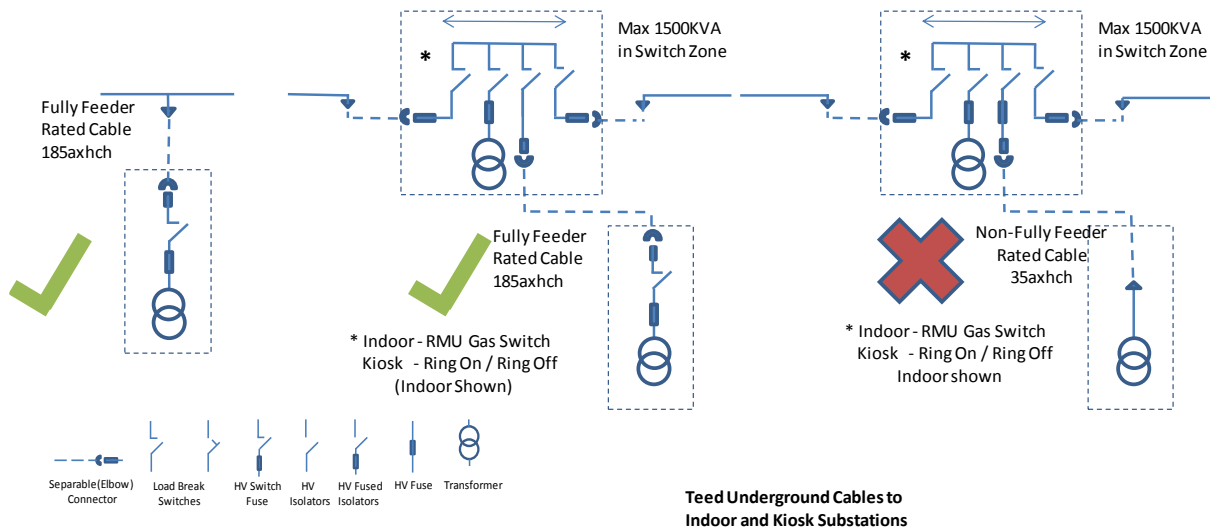
Hence UE's guideline for switch placement for underground cable networks requires:

- A switch at each end where the cable terminates;
- Underground Tees (while not recommended) must be fully feeder rated;
- The total installed transformer capacity per major switch zone should not exceed 2000kVA;
- Individual substations greater than 1000kVA shall be provided with an exclusive switching zone; and
- A loop-through arrangement or tee-off as shown below.



Current URD Switch Placements - Ring On Ring Off

It is now required that all pad mount and kiosk style substations be fitted with switches as per the diagram below.



#### 5.5.4.2 Ferro-resonance

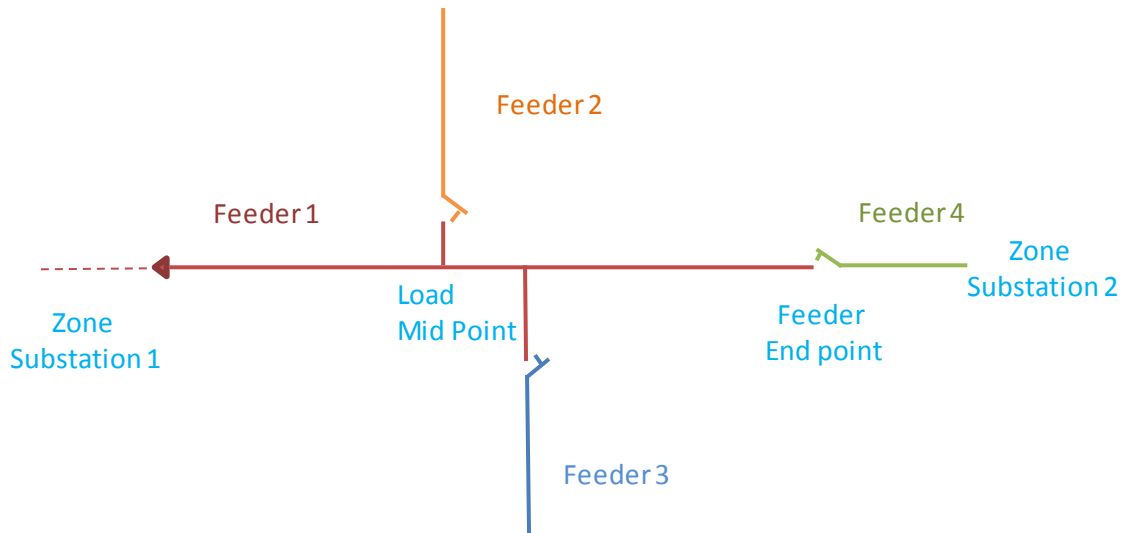
Ferro-resonance can result in high voltages (4 to 7 times normal) when small parasitic capacitances within the cable interact in series with the non-linear inductance of an iron-cored transformer. When a single phase of a 3-phase cable is connected to an unloaded or very lightly loaded transformer, during the period of single phase switching a bi-stable state of oscillation can exist to generate these high voltages. Upon connection of all 3-phases and cessation of switching activities voltage will return to normal.

Ferro-resonance can be prevented by ensuring that single phase switching devices (isolators or fuse links) are not used for operations, only ganged 3 phase switches that ensure disconnection and connection of all 3 phases simultaneously. Where switches are combined with single phase fuse links, the ganged switch must always be operated first, either to isolate the cable and transformer or isolate the transformer from the cable, dependant on the configuration.

#### 5.5.5 Inter-feeder Tie Switches

Inter-feeder ties allow for restoration of supply to customers on a feeder that are downstream of the fault location by providing transfer capability options to adjacent feeders. The guidelines for placement of inter-feeder tie point switches are:

- A minimum of two ties to adjacent feeders are required, which may be to one, or preferably two or more adjacent UE feeders or feeders from another DNSP;
- One tie is acceptable when that tie is being used to provide reserve capacity for a major customer;
- One tie shall be situated close to the end of the feeder downstream of any ACRs and any others roughly equally spaced from the end of the feeder towards the start of the feeder;
- It is desirable for one of these ties to attach to a feeder sourced from a different zone substation or at least from a different bus off the same zone substation;
- Further feeder ties can be established if required for purposes of network flexibility especially if feeders are highly utilised or exposed to high fault activities; and
- No feeder tie is required for a dedicated feeder supplying a larger customer who does not have a reserve capacity agreement.



### Inter-feeder Ties

Consideration should be made to the following customers in determining transfer capability especially if they are on spurs:

- Large sensitive customers;
- Central business districts;
- Hospitals;
- Shopping centre complexes;
- Public venues;
- High-rise buildings;
- Retirement villages;
- Large residential estates; and
- Large industrial estates.

Historical fault performance of feeders should be critically reviewed in order to identify the areas at high risk of feeder faults. The high risk areas should be segregated from low risk areas in order to improve the reliability of supply overall. This can be done with placement of ACRs and remote-controlled switches.

Due to physical constraints such as freeways, rivers, road layout and system configuration, the optimal arrangement is sometimes difficult to achieve and in these situations more than two ties are required to adequately offload the feeder for load transfers.

### 5.5.6 Ring-on-ring-off vs Radial Connections

In underground networks, new kiosks and indoor substations are typically installed in ring-on-ring-off arrangement irrespective of the capacity of the transformer given most of the instances the new substation needs to be cut into an existing cable. Depending on the configuration of the network, inter-feeder kiosks are sometimes used to create radial connections. Given kiosks and indoor substations create their own switch zones, up to 2000kVA substations (single or nett) are typically allowed to connect in radial via an inter-feeder-kiosk depending on the circumstances.

Underground network is a prerequisite for new industrial and URD subdivisions. Most of these large developments are implemented in stages and developer shall provide (or the relevant project planner shall develop) an overall plan to supply the complete site including provisions for staged development. This type of large staged development might leave some parts of the network radially connected until the rest of the stages are completed. Attempt shall be made to minimise this situation while preparing overall plans and staging works. However, such situations are practically unavoidable in some circumstances and excessively expensive to mitigate. Therefore, short term extended radial connections within a staged development are considered acceptable provided that plans are in place to eventually ring them.

In overhead networks, a ring-on-ring-off connection requires two spare poles for cable heads and needs to either retire the overhead conductors between two cable heads or create an open point to break the continuity of the overhead line. This configuration will automatically split the existing switch zone as kiosks and indoor substations are equipped with switches by default. However, connecting a new kiosk or an indoor substation in ring-on-ring-off arrangement is not essential in overhead networks. The decision is generally made based on the additional cost involved in cabling and potential operational flexibility gained through a ring-on-ring-off configuration. Therefore, any new kiosk or indoor substation (or nett installed capacity) less than 1000kVA shall be connected radial in the overhead networks. When the capacity of the new installation (or nett installed capacity) is equal or greater than 1000kVA, the possibility of connecting them in ring-on-ring-off configuration shall be considered. However, if such configuration requires installing a new pole or more than 50 route metres of additional cabling, the requirement for ring-on-ring-off connection needs to be re-evaluated on a case-by-case basis. In the instances where the cost involved with a ring-on-ring-off connection is prohibitively expensive, radial connections shall be allowed up to 2000kVA.

HV customer connections are typically of radial configuration unless the customer has requested reserve capacity, for which a Reserve Capacity Agreement will need to be in place.

### 5.5.7 Replacement Guidelines

Reliability issues have arisen regarding HV air-break switches in the distribution system. The issue arises when attempts are made to close the switch. This is caused by a mechanical issue with closing the switch blade contacts and as such crews cannot be sure whether they will be able to close these switches after having opened one. Many of these switches are now reaching end of life and require replacement. These switches have widely varying age (with a significant number that have been in service for at least 40 years).

UE now installs fully enclosed gas-insulated switches – a sulphur hexafluoride filled device that is much smaller, safer, easier to operate and more reliable. It is proposed to eventually replace all of these air-break switches with manual or remote controlled ready gas-insulated switches. This provides an opportunity to revise the locations where these switches are situated and attempt to place them around the network in a more optimal fashion.

Before any existing switch is replaced, it is essential to review whether a switch is still required in the current location and if it should be removed completely or relocated to another site with a new switch. If a switch is required at the current location then a decision should be taken to replace it with a gas insulated switch.

Considerations are:

1. Is the switch an open point? If so then an appraisal of the loads on the feeder and the local configuration is appropriate. Evaluation of neighbouring feeders for available transfer capacity at peak load needs to be performed. The Principal Engineer Network Planning should be consulted as he may already have long term plans as to how the system should be reconfigured and switching contingency plans for emergency situations.
2. The current status of the switches either side of this switch. Assessment of the long term plan for these switches, if any and operating condition of adjacent switches
3. Loading of the adjacent sections and whether two adjacent switch zones can be rolled into one without compromising the feeder transfer capacity or sectionalisation capability.

The guidelines for air-break replacement are as follows:

1. Identify an air-break switch that is
  - a. known to be faulty, or
  - b. likely to be operated the most frequently, or
  - c. on an inter-feeder tie point, or
  - d. clustered with other air-break switches.

2. Remove the switch completely if removing the switch does not violate UE's switch placement guidelines (discussed earlier)
3. Otherwise either move and replace, or replace the switch to achieve as close as possible to UE's switch placement guidelines (discussed earlier).

When moving a switch, locating a suitable pole for the switch requires sufficient space between the lower and upper cross arms (in some cases it is possible to reposition the lower cross arm to allow a greater amount of space). A strain pole is required or existing insulator fittings will require replacement with a strain arrangement, so that an open bridge can be placed in line for that switch.

Uniform location of switches is important but some art is required to optimise placement maximising the number of switchable redundant paths, and minimising the area affected by a fault (i.e. isolate the fault to as smaller segment of network as possible).

A decision also needs to be made if the new switch to be installed is to have remote control ready capability. The guidelines for whether a switch needs to be remote controlled ready are as follows:

1. If the switch is at a normally open point between two different feeders (with an ACR upstream); or
2. If the switch is roughly midway (or divides the number of customers in half) between two other remote controlled devices (e.g. Feeder CB, ACR or RCGS).

### 5.5.8 Spurs

A spur is a radial line from the main feeder backbone. Development of spurs on the urban network should be closely monitored particularly if the total installed transformer capacity on a spur exceeds 2000kVA or critical customers exist on the spur. The Principal Engineer Network Planning should look at options to connect the end of the spur in a loop arrangement or to another feeder with an open switch. Spurs with large loads also limit the switching flexibility in the network for load balancing and for feeder outages.

### 5.5.9 Remote Control Switching & Distribution Feeder Automation

Placing remote control capability on switches on open points between feeders supplied from adjacent zone substation would allow the use of 10-minute transformer ratings and avoid load shedding. This would defer augmentation and improve the reliability performance by reducing CAIDI, eliminating the need to travel to the site to switch the network and restore supply.

UE has established a Distribution Feeder Automation (DFA) scheme called FLISR. This system is intended to improve system reliability performance by allowing switching to be undertaken in less than 1 minute, reducing CAIDI and SAIFI by shifting permanent interruptions to momentary interruptions, known as MAIFI. FLISR takes advantage of the existing system configurations and capacities. It involves the remote control of switches for the purposes of rapid load transfers between feeders.

For FLISR to work effectively, there needs to be sufficient spare capacity in the feeders to carry the transferred load. In areas where feeders are nearing their capacity, implementing a DFA may require feeder upgrades to be performed as well. In such instances, suppression of DFA schemes during high demand days can be considered. It will allow utilising the capability of the network for most of the time in a year for DFA except high demand days, which can be predicted in advance based on the weather forecast.

For operational safety purposes, it is required to position overhead LV open points at the pole location of the remote controlled switch or automatic circuit recloser.

### 5.5.10 HV Open Points

An open point is a switch in the normally-open position on a feeder. Open points should be reviewed twice a year – prior to November for the summer arrangement, then from April for the winter arrangement.

Open point changes should be performed for the reasons indicated below in decreasing priority order:

1. To keep feeders within 100% of N rating;

2. To keep zone substations within 100% of N cyclic rating;
3. To optimise network reliability;
4. To minimise network losses; and
5. To minimise zone substation, terminal station or transmission load at risk.

Open point changes should not be done to balance zone substation loads if the change has a negative impact on the reliability of the feeder taking up the load.

Ad-hoc open point changes may be required during the year if large feeder load variations are expected.

Open point changes should be considered in the load forecasting process for planned load transfers.

Consideration must be given to voltage levels, protection grading and backup protection reach before making an open point change. The Secondary Assets team should be consulted on protection related issues.

Under no circumstances shall the backup protection reach or protection grading be compromised with an open point change. If such an open point change is required, then consideration should be given to installing an ACR, reconductoring, fusing or a bus distance protection scheme at the zone substation.

It is preferable from an operational perspective to change an open point using gas insulated or indoor switchgear if possible. Using isolators to change open points should be avoided.

It is preferable to have a remote controlled switching device as the open-point to facilitate fault restoration.

Open point changes shall be issued by the Principal Engineer Network Planning by way of a formal written request to the UE NCC (copied to UE's Data Quality Analyst). The NCC will enact the change and update the operating diagrams. Network Planning shall be notified upon completion.

Permanent open point changes on the UE network shall only be enacted with the approval of the Principal Engineer Network Planning.

Below is an example of the [switching advice template](#) which when prepared should be saved at

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/SwitchingInstructions>

**B**

Date: dd Mmm 20yy  
Ref: SSA-20vv-dd

David Kowal NCC Operations Manager <a href="mailto:david.kowal@ue.com.au">david.kowal@ue.com.au</a>	Robert Simpkin Secondary Systems Manager <a href="mailto:robert.simpkin@ue.com.au">robert.simpkin@ue.com.au</a>	Justin Moon Capex project team leader <a href="mailto:Justin.Moon@ue.com.au">Justin.Moon@ue.com.au</a>	Rick Engel Data Quality Analyst <a href="mailto:Rick.Engel@ue.com.au">Rick.Engel@ue.com.au</a>
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Sujeewa Vithana/ Roshanth Sivanathan  
Principal Engineer Network Planning  
[Planning@ue.com.au](mailto:Planning@ue.com.au)  
03 8846 9746/ 03 8846 9528

< Insert a brief description of the need of the proposed switching >

< Indicated whether the transfers are permanent and relevant operating diagrams are to be updated accordingly or they are temporary >

*The switching instructions should be performed in the following sequence <if any switching can be done independently, specifically state those > together with any applicable protection setting and configuration (SIOS) changes:*

[illegible]

Legend: O - Open, C - Closed

The details of the relevant protection setting and/or SCADA changes, if any, are as follows:

Step	Switch No	Setting reviewed by	SEMS No	Description
x.x	xxxx	UE SP	xxxx	Apply setting in SEMS xxxxxx update 5758
x.x	xxxx	UE SP	xxxx	

Within 48 hours of the completion of the above changes, the Operations Planner is to email a scanned signed copy of this form to the Reconnecting Officer for the updating of records.

Action check list:

Action	Status	Comments
Protection settings are applied, if any	<input type="checkbox"/>	
Request is raised to update SCADA, if required	<input type="checkbox"/>	
Field switching is completed	<input type="checkbox"/>	
SCADA is updated, if required	<input type="checkbox"/>	
Request is raised to update GIS and operating diagrams	<input type="checkbox"/>	
GIS and operating diagrams are updated	<input type="checkbox"/>	

Completed On: .....

Signed: \_\_\_\_\_  
(Operations Planner)

In most cases the factor limiting the connection of additional equipment and customers is the current level. Capacitors reduce the current loading which has a spin-off of being able to defer augmentation of those assets. Poor power factor may

also limit the ratings of zone substation transformers due to over-voltages being generated on tapping. Improving power factor in these instances will increase the ratings of the transformers in these zone substations, again deferring capital expenditure.

Installation of capacitor banks improve power factor on the network. DNSPs are required to provide a minimum power factor level at the points of connection as part of the Use of System Agreement with AEMO. UE should target a power factor on distribution feeders of 0.9 lagging to unity at peak demand and being close to unity is preferable.

## 5.6.2 Placement

The standard size for line capacitors is 0.9MVAR. Line capacitors shall be targeted on feeders where the power factor on the feeder is lagging and where the

1. Feeder power factor is worse than 0.9 lagging at peak demand, or
2. Zone substation power factor is worse than 0.9 lagging at peak demand, or
3. Terminal station power factor is worse than 0.95 lagging at peak demand, or
4. Feeder voltage control is an issue due to high reactive demand or line length, or
5. The zone substation rating is limited by tap over-voltage.

Line capacitors are prone to the following problems. These problems can be easily avoided with careful placement planning.

Problem	Observed Effect	Solution
Pre-strike and inrush	One or two fuses blow. Voltage spiking on waveform	Minimum spacing and adjacent capacitor banks should preferably have different switching times.
High frequency noise	All three switches don't close together. Controllers open switches inadvertently after a close.	Controllers must have control cable screening.
Harmonics	Three fuses blow. Damage to consumer equipment. Humming capacitor bank.  Note: fuses can also blow as a result of an auto-reclose on the feeder. Blown fuses are not necessarily a symptom of harmonics.	PSS/SINCAL studies carried out to confirm resonance. Capacitor bank should be relocated or a harmonic filter installed if the distortion at the zone substation bus is violating regulatory limits.
High voltage	Customer Complaints. Leading power factor feeder.	Limit number of capacitors per feeder. Adjust switching times to minimise leading power factor. Adjust distribution taps. Adjust zone substation default voltage set-point downward.
Switching transients	Customer complaints of RCDs tripping	Adjust switching times to higher demand periods. Advise customer to replace RCD. Move the capacitor bank away from the distribution transformer affected.



Out of taps at the zone substation.	Rise in zone substation bus voltage	Change switching settings of feeder or zone substation capacitors to minimise occurrence of leading power factor.
Lightning strike.	Cans show signs of bulging or excessive humming.	The capacitance of each of the cans should be measured if it is suspected that a can is faulty. Capacitor cans should be replaced.

The following guidelines shall be considered when placing capacitors:

- Capacitors can only be placed on the overhead system.
- The installed capacity of the capacitors shall not exceed the maximum feeder reactive demand.
- Capacitors on the 22kV system shall be placed no closer than 300 metres apart. Capacitors on the 11kV system shall be placed no closer than 500 metres apart.
- Given capacitor banks utilise BA fuses, capacitors can only be placed in locations where the fault level is less than 10kA.
- Capacitors shall be 900kVAr in size and shall only be placed on 22kV and 11kV feeders
- VAr controlled line capacitor banks are no longer used because zone substation capacitor banks are progressively being upgraded to VAr controllers. Zone substation capacitor banks will therefore supply the shortfall in reactive power demand not supplied from the line capacitors.
- A maximum of five capacitor banks shall be placed on a 22kV feeder. A maximum of three capacitor banks shall be placed on an 11kV feeder. Exceptions may apply if the feeder has an abnormally high reactive load. This restriction is to avoid high voltage complaints on the feeder.
- Capacitors shall be placed near large lagging reactive loads.
- Feeders with uniformly distributed loads,
  - for the first line capacitor, the optimum placement is  $\frac{2}{3}$  down the length of the feeder
  - for the second line capacitor, the optimum placement is  $\frac{1}{3}$  down the length of the feeder
  - for the third line capacitor, the optimum placement is  $\frac{1}{2}$  down the length of the feeder
  - for the fourth line capacitor, the optimum placement is  $\frac{5}{6}$  down the length of the feeder
  - for the fifth line capacitor, the optimum placement is  $\frac{1}{6}$  down the length of the feeder provided fault level is less than 10kA.
- The power system simulator PSS/SINCAL should be used if placement positions or harmonic resonance needs to be assessed. .
- Capacitors are preferred on the feeder backbone but not necessary if it is more practical to place a capacitor bank on an unfused spur.
- The Principal Engineer Network Planning must provide the Service Provider with pole LIS options
  - Not on road intersections
  - Preferably on intermediate poles
  - Remote from telecommunication pits

- Not in direct view of a double storey property window

### 5.6.3 Switching Settings

With the availability of SCADA reactive loading on feeders, switching settings can now be tuned more accurately.

Line capacitors shall be switched so that the feeder minimises its operation in the leading power factor region. This may not be possible for all times of the year given the large variability of load curves.

- Fixed capacitors shall be placed on the feeder until the minimum annual reactive load for the feeder is reduced to zero.
- Time switched capacitors shall be placed until the average daily reactive peak load is reduced to the daily minimum.
- Temperature switched capacitor banks shall be placed on temperature sensitive feeders until the annual peak reactive demand is reduced to the daily minimum.
- No units shall be voltage controlled but all must be set with a secondary override to avoid high voltage.

Generally time switched units have an on time between 6am and 9am and an off time between 5pm and 8pm. Time switched capacitors shall be graded in time so as not to produce large voltage variations at the zone substation due to large numbers of them on the network switching in or out simultaneously. Only time switched units should be set to stay off on public holidays.

As a guide, temperature switched units shall be switched on at 30 degrees Celsius and switched off at 24 degrees Celsius. The low switch off temperature is to take into account the thermal time constant of buildings. The temperature is not likely to drop to 24 degrees after a hot day until well into the evening or after a cool change. This will ensure the capacitors stay on to support evening peak domestic air-conditioning demand.

For pole top capacitor banks installed on distribution feeders, the switching settings should be customised to the feeder load profile. Four options are available:

Mode	Description	Typical Settings
<b>Fixed</b>	Always on	ON
<b>Time switched</b>	Switches daily (usually weekdays)	ON: 8AM; OFF: 6PM; MON-FRI
<b>Weekly switched</b>	Switches weekly (usually weekdays)	ON: MON 8AM; OFF FRI 6PM
<b>Temperature</b>	On above a defined temperature	ON: 30°C; OFF: 24°C

The zone substation capacitor switching settings should be reviewed to ensure the zone substation operates at close to unity power factor. Operation of the zone substation slightly leading is not an issue provided that the zone substation transformers are not tapped to their maximum extent and the terminal stations are not operating at leading power factor.

The line capacitor switching settings are stored in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/ReactivePowerandVoltageRegulation/Line%20Capacitors%20Settings>

The public holiday settings and daylight savings (where appropriate) settings shall be checked and updated upon every unit and backup batteries replaced on a 4 year cyclic basis (through the pre-summer inspection process). Where a daylight savings feature is not available, the switching settings shall be optimised for a summer load curve.

Switching settings shall be reviewed with respect to both feeder and zone substation reactive loading basis annually.



## 6. Planning of Zone Substations

Zone Substation Network Planning is undertaken by the Principal Engineer Network Planning. Capex programmes associated with this planning fall under the DZ(A) activity code.

A zone substation is a site that transforms sub-transmission voltages (typically 66kV and sometimes 22kV) down to distribution voltages (typically 22kV, 11kV and sometimes 6.6kV).

Zone substations may have up to three transformers in parallel as an ultimate design, but in some cases where the load is exceptionally high, may have two sets of two transformers in parallel separated by an open bus tie circuit breaker on the secondary side which automatically closes in the event of a transformer outage. This normally open tie is required to limit fault levels.

Generally two incoming sub-transmission lines feed the zone substation, in a loop or meshed arrangement. Sub-transmission lines generally have line circuit breakers to fully switch the line, however in legacy zone substations, the absence of line circuit breakers mean that sub-transmission lines are switched with a zone substation transformer. For ring bus arrangements, there may be up to four or five sub-transmission line entries/exits into the zone substation.

Each transformer primary winding in the zone substation is connected to its own sub-transmission bus which is then tied to adjacent busses by a bus-tie circuit breaker.

On the secondary side of the transformers is another bus per transformer connected using a transformer incomer circuit breaker with the bus also tied with other busses by a bus-tie circuit breaker.

This bus has feeder circuit breakers attached through which distribution feeders are connected to the buses.

UE's overall zone substation planning philosophy is to use a probabilistic risk assessment approach to determine the acceptable loading level of zone substations. In the past, the approach was to have sufficient capability such that for loss (planned or forced) of any single transformer during maximum demand, the voltages and loading on all remaining in-service elements would remain within their design limits/ratings for the duration of the outage. This (N-1) criterion is usually still applicable when short-time emergency ratings are used which provides some level of operating risk. The nature of the load and capital investment constraints may force significant compromises in the philosophy referred to above. Such compromises generally involve accepting more risk where load may have to be shed for single contingencies.

### 6.1 Zone Substation Ratings

#### 6.1.1 Overall Zone Substation Ratings

Zone substation ratings are either limited thermally by switchgear connections, CTs, buses or transformers or by transformer over-fluxing. In most cases, the winter ratings of a zone substation are higher than the summer ratings. Peak demand typically occurs during summer

Most zone substations' capacity is limited by either the transformer, switchgear or the busbar. This is standard practice given that these are the most expensive items of plant in the station. For zone substations limited by transformer ratings, short time emergency ratings can be assigned to increase the zone substation ratings. However, the adoption of a 2-hour emergency rating or the 10-minute emergency rating largely depends on the availability of remote controlled switches installed on feeders from adjacent zone substations. A 10-minute rating is used for operational risk management only, and not adopted in planning of the network.

Each zone substation has its own unique rating depending on the minimum rating of each transformer leg and the degree of load balancing between them. Imbalance in transformer loading with respect to their ratings may also reduce the station rating. Such imbalance in load sharing occurs as a result of mismatches in transformer impedances and/or the impedance differences created by unequal lengths of transformer cables.

The thermal limitation of a zone substation is generally on the transformer secondary side rather than the primary side. Where the constraint is caused by connections or CTs, consideration should be made to upgrade these relatively low cost assets so that the limitation is the switchgear, buses or transformer.

For large reactive loading on zone substations, the voltage regulation across a transformer(s) can be very large when another transformer trips out of service. This can result in the transformer(s) running out of taps or over-fluxing. This will limit the station rating. The station rating can be increased closer to the thermal rating of the transformers if power factor correction is implemented at the station or on the distribution feeders.

The cable connection from the transformer secondary to the bus typically does not always match the transformer capacity. This constraint may reduce the overall station rating. In due course, the cables may need to be replaced to make the full capacity of the transformer available. In some instances spare conduits are available between the transformer and switchgear to connect a parallel cable. Other equipment such as isolators or droppers in the station may also limit the rating.

The limiting factor in any new zone station should be the transformers or buses as these are the most expensive items of the plant.

### 6.1.2 Overload Ratings Based On Transformer Temperature Condition

Overload ratings of zone substations may be available if remote transformer temperature monitoring is installed at a zone substation. Unlike the cyclic ratings which take advantage of the rise and fall of the load curve on a cyclic basis and the emergency ratings which utilise a theoretical model to derive an Ampere rating, the overload rating utilises the temperature constraints of the transformer. Given that the cyclic ratings are based on high ambient temperatures, a contingency during cooler conditions potentially means higher ratings could be possible. This is where the overload rating becomes useful with a direct reading of transformer oil temperature. Some calculation adjustment of the temperature reading need to be made to account for the fact that the transducers will not be monitoring the "hot spot" of the transformer.

### 6.1.3 Recording Zone Substation Ratings

All zone substation and power transformer ratings shall be recorded in the "Loadings and Ratings Database". This is the primary source of rating information for zone substations and transformers.

Furthermore, the Plant Data Sheets contain zone substation information regarding:

- Single Line Diagram
- Transformer ratings, tapping range and impedances
- Other primary equipment ratings and impedances

These data sheets are owned by the Primary Assets team. The Principal Engineer Network Planning should advise the Primary Assets team if changes to these drawings are required.

Hand written changes on the data sheets are not a permanent solution and if done should be done in red pen and accompanied by a signature and date. An updated hardcopy of the circuit data sheet should be requested as soon as possible once a change has been made to minimise any ambiguities in future.

## 6.2 Zone Substation Topologies

There are various zone substation topologies that are used in the UE network. Zone substation single line diagrams are located in iView which can be accessed through Citrix.

Sub-transmission line breakers are only required on single transformer substations and are often economic on two-transformer zone substations where installation of a third transformer can be deferred. Placing line circuit breakers on three transformer substations may not provide any significant benefits unless 22kV or 11kV bus is split due to fault level limitation.

Circuit breakers shall be installed on the distribution side of zone substation transformers in all new zone substations so that the station is a fully switched station. This will protect the zone substation from blackouts due to failure of distribution feeder primary protection or faults within the zone substation.

### 6.2.1 Full Transformer Switching

This is the standard zone substation topology for UE.

For a fault occurring anywhere between the sub-transmission bus and the distribution buses, a transformer can be completely isolated through automatic protection tripping of the local or remote sub-transmission line circuit breaker, the

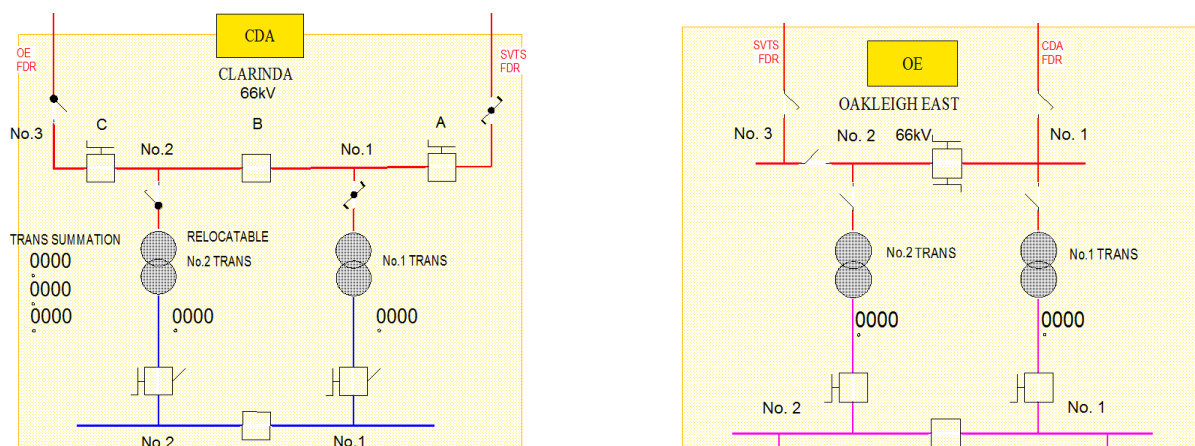
sub-transmission bus tie circuit breaker and the transformer incomer circuit breaker, without loss of supply to the high voltage distribution buses. The remaining transformer(s) will carry the zone substation load until operators arrive to assess the situation.

A zone substation with full transformer switching may be operated at the 2-hour emergency rating of the zone substation with one transformer out of service without risk of damage. Within two hours the load must be transferred away or shed on a cyclic basis to reduce the station to the cyclic rating of the remaining transformers.

The station may be loaded to a 10-minute rating provided that a remote controlled feeder switching is in place to transfer the load away within this time.

Any load in excess of the short-time emergency dynamic ratings will need to be shed as soon as possible.

Auto-reclose on the sub-transmission lines reduces the risk of this situation considerably given that a trip of a sub-transmission line is the most probable contingency and the risk of a permanent fault is smaller than a transient fault.



## 6.2.2 Non-Fully Switched Transformers

This topology is no longer used by UE.

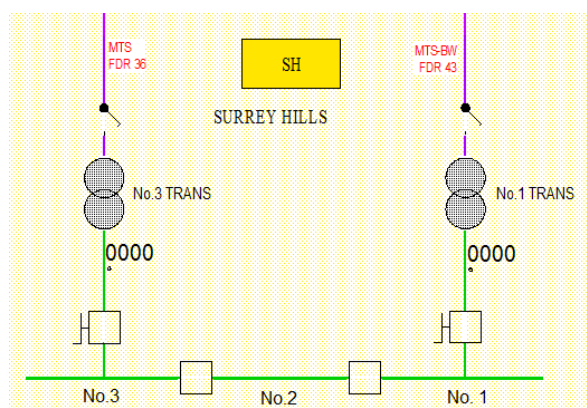
Zone substations FTN, MTN and RBD used to be of this configuration prior to their respective rebuilds. This topology banked all transformers together into the one switching zone effectively reducing the number of circuit breakers required. A fault anywhere within the zone substation resulted in loss of supply to the whole zone substation.

## 6.2.3 Radially Supplied Transformers

This topology is still used at BW, SH and STO zone substations but is no longer a standard topology.

This topology connects one sub-transmission line onto one transformer with the transformers only tied together at on the secondary side. This reduces the flexibility of the zone substation as a transformer needs to be taken out of service whenever a sub-transmission line is out of service and vice versa.





## 6.3 Power Transformers

### 6.3.1 Transformer Ratings and Specifications

Under system normal operation, zone substation transformers would typically be operated to their 'N' nameplate ratings. This generally provides sufficient spare capacity to transfer load onto the zone substation and allow its transformers to be operated up to their cyclic ratings in the event of an emergency at an adjacent zone substation. It should be noted that while this is an operational guideline for planning, the maximum allowable loading that triggers an augmentation is determined purely on economic grounds and transformers can be loaded to the 'N' cyclic rating under system normal conditions before offloading is required.

For an ultimate developed zone substation with three 20/27/33MVA transformers, this means the zone substation could be loaded to  $3 \times 33\text{MVA} = 99\text{MVA}$  under (N) system normal nameplate conditions. This operationally aligns well with the 2-hour (N-1) emergency short-time rating, assuming a 2-hour rating of 49.5MVA per transformer and the bus rating of 1250/2500A.

If station (N) cyclic ratings are reserved for emergency situations, in the case of a zone substation with three 20/27/33MVA transformers, this means the station could be loaded to a maximum of  $3 \times 44\text{MVA} = 132\text{MVA}$  under emergency conditions assuming a cyclic rating of 44MVA per transformer. This will remain within the bus ratings of the zone substation. This provides 33MVA of spare capacity, enough to totally offload a transformer from an adjacent zone substation in the event of an emergency.

When a transformer is out of service, it is possible to use the cyclic ratings of the transformers keeping the core temperatures at safe levels. These cyclic ratings are available as the load profile is not flat. The cyclic ratings are higher than the nameplate ratings meaning the transformers can be loaded above their nameplate rating for a period of time. The higher the assigned cyclic rating, the shorter the time the transformers can be operated before exceeding safe core temperatures. Accelerated loss of transformer life occurs when the transformers exceed their safe core temperatures.

Using the concepts of cyclic and limited cyclic ratings, it is possible to assign higher ratings than the nameplate ratings for transformers. These ratings are based upon the formulae and temperature/life curve derived from AS1078 - 1984 and the following assumptions:

Assumptions for Transformer Cyclic Ratings	
Top Oil Temperature Limit:	105 °C
Hot Spot Temperature Limit:	140 °C
Maximum Current Limit (cyclic):	1.50 times rated current
Maximum Current Limit ( limited cyclic):	1.50 times rated current

<b>Daily Loss of Life (cyclic):</b>	0.03%
<b>Daily Loss of Life (limited cyclic):</b>	0.12%

Hence, if a transformer is loaded at its cyclic rating, each 24-hour of such loading will account for 0.03% of loss of transformer life, i.e., the transformer will have a life of about 10 years. Similarly, if a transformer is loaded at its limited cyclic rating, each 24 hour of such loading will account for 0.12% of loss of transformer life, i.e. the transformer will have a life of about 2.5 years. The alignment of Network Planning Policy between CP/PAL & UE found that UE could adopt a higher loss of life factor based on the values used by CP/PAL. This however does not consider the age of the fleet nor other differences in the operational and asset replacement strategies. Should an aggressive approach be adopted, a higher cyclic rating could be achieved at zone substations with older fleet of transformers (as for modern transformers, the rating is most likely be limited by the switchgear). Given this, this may defer some augmentation works, but it could be offset by the fact that additional maintenance works would need to be in place to allow the transformer to operate harder (or alternative, adopt a higher failure rate in the absence of increased maintenance costs). These factors are to be considered on a case-by-case by the Primary Asset Team. Any changes to the planning assumption as a result of this shall be considered going forward.

Zone Substation transformers are generally assigned four ratings:

1. **Cyclic Rating (CR):** This is the permissible daily peak demand to which the transformer(s) may be subjected over a nominated period when a major plant item is out of service. (90 days has been used, being the practical repair period in the event of a major plant failure with no spares)
2. **Limited Cyclic Rating (LCR):** This is the permissible peak demand to which the transformer(s) may be subjected over one daily load cycle, after which the transformer load must be reduced to its CR.
3. **Two Hour Emergency Rating (2hr ER):** This is the permissible peak demand to which the transformer(s) may be subjected over 2 hours, after which the transformer load must be reduced to its CR.
4. **10 Minute Emergency Rating (10min ER):** This is the permissible peak demand to which the transformer(s) may be subjected over 10 minutes, after which the transformer load must be reduced to its CR.

In applying these ratings, the philosophy has been that a zone substation can be loaded up to its (N-1) limited cyclic rating provided there was adequate transfer capability to reduce the load on the station to its cyclic rating within 24 hours. In most contingency situations, however, it is possible to effect load transfers within 2 hours. Hence, the concept of “2 hour emergency rating” was introduced and applied at critically loaded zone substations to continue to manage operational risk while operating at higher utilisations. With the implementation of remote monitoring and control schemes at zone substations and remote switching on the distribution network, shorter time ratings of 10 minutes have been introduced to manage the risk. Operation of the zone substation above the 10-minute rating will require immediate load shedding following a contingency.

The standard installed transformer rating is now 20/27/33 MVA or 20/30/33 MVA.

Capacity	Circulation Type	
<b>20MVA</b>	ONAN	Oil Natural, Air Natural
<b>27MVA</b>	ONAF	Oil Natural, Air Forced (Fans)
<b>33MVA</b>	OFAF or ODAF	Oil Forced/Directed (Pumps), Air Forced (Fans)

These ratings are further increased to give the cyclic and emergency ratings as above by application of guidelines in Australian Standards 1078, Part 1-192, Guide to Loading of Oil immersed Transformers.

This generally results in summer CR, LCR and 2hr emergency rating (ER) of:



Type	Description	Summer Capacity
CR	Cyclic Rating	44.0MVA
LCR	Limited Cyclic Rating	46.0MVA
2hr ER	2 Hour Emergency Rating	49.5MVA

This is calculated and assigned on a station by station basis. Other local factors almost always reduce these figures, in particular the bus ratings which are limited to 1250/2500A.

Transformers should be three-phase, connected wye-wye-delta (tertiary) for 22kV, delta-wye for 11kV and have per-unit impedances on a nameplate rating basis as close as possible to balance the loading across the parallel transformers. Series reactors can be used to balance the loading if necessary, although the preference is to select an appropriate transformer impedance to achieve the balancing.

Transformer Type	Vector Group	Impedance
66/22kV	Yyn0d11	9.75% on 20MVA (16.1% on 33MVA)
66/11kV	Dyn1	15.0% on 20 MVA (24.8% on 33 MVA)

To contain the initial capital expenditure when establishing a new zone substation, the substation is usually only developed with one transformer with an ultimate of three transformers.

### 6.3.2 Setting Voltage Levels at Zone Substations

The OLTC shall be on the primary side of the zone substation transformers and be used to regulate the voltage on the secondary side of the zone substation transformers. A suitable dead-band should be selected (typically greater than the step size) to minimise tap operations when the set point is programmed into the OLTC controller.

Transformer Type	No. Taps	Step Size	Range
66/22kV	17	1.25%	+15% to -5%
66/11kV	17	1.25%	+15% to -5%

Transformers with a +25% boost or a 2.5% step size shall no longer be procured unless they are procured to match the tapping range of an existing parallel transformer.

Most zone substation buses in UE were traditionally held to a constant level of voltage from +1 to +6% of nominal. This level was usually the highest that could be applied at the particular zone station as determined by the highest 'buck tap' available on the distribution transformers serviced from that zone substation. With the installation of pole mounted capacitors the feeder voltage drop will be significantly less. Furthermore, the installation of solar photo-voltaic cells at customer premises also raises voltages further reducing the need to keep zone substation bus voltages high. Hence there has been a trend over recent years to reduce bus default voltage set-points. For this reason the DVMS now regulates float voltages at the lower end of the range for most of the time to maintain LV voltages within limits, and only acts to boost voltages during times of high demand.

When the bus ties are closed the zone substation should operate on grouped voltage control. When the bus ties are open, the station should operate on independent voltage control (assuming a VT is available for each bus group). When transformers have significantly different impedance or no ability to regulate the voltage, reverse reactance should be implemented to allow one transformer to follow the tapping of another transformer by minimising circulating current. This is typically employed on the relocatable transformers.

The default voltage regulation settings at zone substations are stored in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/ReactivePowerandVoltageRegulation/Voltage%20Regulation%20Settings/Zone%20Substation>

UE has implemented a dynamic float voltage approach which uses voltage feedback from AMI metering to try to minimise the number of steady state over-voltages and under-voltages. This is implemented in the DVMS and is applied to all UE zone substations. It is not applied for UE customers supplied from RWT or from other DNSP zone substations.

## 6.4 Neutral Earth Resistors

Neutral earth resistors (NERs) should be installed at all new zone substations as they improve the quality of supply to customers with reduced voltage dips during phase to ground faults. New zone substations are also specified to allow for the future installation of a resonant earthing device.

NERs should be shared between the transformers.

Voltage	Size
11kV	4 ohms
22kV	8 ohms

Where there are two 22kV zone substations operating in parallel with a split bus (like SV/SVW), 16 ohm NERs may be applied.

A normally-open bypass switch must be installed with an NER to allow maintenance without a zone substation outage. At zone substations requiring protection reach through the transformers for the sub-transmission system, a bypass circuit breaker may be needed.

## 6.5 Feeder Exits

### 6.5.1 Number of Feeders

For zone substations with an ultimate nameplate rating of 99MVA, and feeders with a 350A rating, the arithmetic points to 4 feeders per bus for 22kV and 7 feeders per bus for 11kV, assuming a 67% utilisation.

Under emergencies, a transformer cyclic rating of 44MVA is ideally suited to a bus rating of 1250A at 22kV (or 2500A at 11kV). Feeders with a typical rating of 350A loaded up to an average of 85% suggests 4 to 5 22kV feeders per bus and possibly 6 to 8 feeder circuit breakers per bus for 11kV.

Transformer Type	Feeders per bus	Total number of feeders (ultimate)
66/22kV	4 or 5	12 to 15 (includes capacitor banks if required)
66/11kV	6	18 (includes capacitor banks if required)

Given the existing backbones are predominantly used when creating new feeders, all the new feeders may not be able to be rated at 350A depending on the conductors used in the existing backbones that form part of the new feeder. Therefore, more feeders may be required to utilise the full transformer capability. The standard 11kV and 22kV indoor switchboards used in UE network consist of six and five feeder circuit breakers respectively. Typically two of those circuit breakers are intended for two sets of switched capacitor banks at the zone substation.

## 6.5.2 Naming Convention

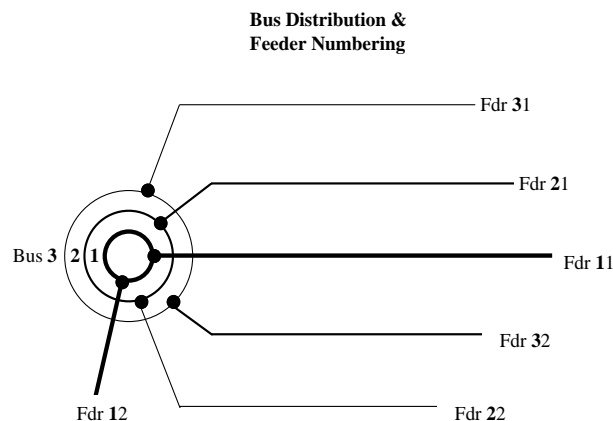
Feeders should be numbered with 2 digits. All feeders off the No. 1 bus have a numerical prefix of “1”. All feeders off the No. 2 Bus have a prefix of “2”, etc. The second digit should be in incrementing order beginning with “1” and typically represents the position of the feeder circuit breaker. The feeder name is to include the abbreviated zone substation name. Historically, zone substation names consist of single or two characters. The present convention is to use three characters. The zone substation name is generally based on the name of the suburb or areas within the suburb in which it is sited. The zone substation name is generally made up of the first letter of the suburb and the last two letters being the first and last letters of the last syllable.

Region		Abbreviation
Dandenong South	(D)andenong-(S)out(h)	DSH
Rosebud	(R)ose-(b)u(d)	RBD
Dandenong Valley	(D)andenong-(V)alle(y)	DVY
Mulgrave	(M)ul-(g)rav(e)	MGE

Hence feeders are labelled like so: MGE11, MGE12, MGE21, etc.

The Distribution Annual Planning Reports of other Victorian DNSPs should be checked to ensure that the new zone substation naming abbreviations being used is unique for Victoria. For example, the future Scoresby zone substation would generally be named SBY, however this name has been used for JEN’s Sunbury zone substation.

## 6.5.3 Bus Distribution



Adjacent feeders should be connected to different buses (interleaved) so that for the loss of a bus, two adjacent feeders connected to healthy buses are available to carry load. This is not possible for a single transformer zone substation.

If a zone substation is to have a spare circuit breaker for a future feeder, then the breaker should be placed on the bus connected to the smaller transformer. This is to balance loading on the transformers if the bus tie is ever opened.

## 6.5.4 Circuit Breakers

New feeder circuit breakers should be rated for a 630 Amp load current maximum. This is a standard breaker size and will allow for jumbo feeders in the future.

Buses should be interconnected with normally closed bus tie circuit breakers unless closing these breakers results in a violation of maximum fault levels.

As circuit breakers are protective devices they should never be operated above their nameplate rating.

## 6.6 Capacitor Banks

### 6.6.1 Background

Reactive current on the system ties up capacity of system elements that could otherwise be used for supplying real power. It also increases the voltage drop and losses as both are a function of current and resistance in system elements. Reactive current causes UE to unnecessarily spend additional capital.

Capacitor banks placed as close as possible to poor power factor load will release additional upstream network capacity by reducing current, and hence losses in these elements. The voltage profiles on the system will also improve.

In the absence of customers installing power factor correction, UE installs switched capacitor banks at zone substations in discretely sized blocks and along distribution feeders in the form of pole top devices. The application of line capacitors is discussed in Section 5.6.

Installing power factor correction capacitors usually provides a cost effective way of delaying the need for more expensive capacity augmentation.

### 6.6.2 Size

The size of the bank (or modules) is determined by two factors:

- the amount of power factor correction required; and
- the voltage changes imposed on the system when/if the unit is switched on and off.

When a capacitor bank switches in or out there is an instantaneous change of voltage. If large enough, this can be seen by customers and their equipment. The voltage remains at its new level until the voltage regulating relay times out and tap changes are initiated on the zone substation transformers by the OLTC, typically two to three minutes.

The size of this voltage change is determined by the fault level at the connection point and the size of the capacitor bank. The size of the capacitor bank or module segment is to be chosen such that the voltage change brought about on the network through switching of that segment is to be kept below 2.5%. The most common size of zone substation capacitor banks or their modules to achieve this requirement is generally between 3 and 8 MVar.

Step switches are typically used with capacitor banks to enable more granular switching so that voltage violations due to capacitor switching can be avoided.

### 6.6.3 Switching

Capacitor banks are switched in and out according to the local loading.

The capacitor banks at zone substations should only be switched into service if the zone substation has a lagging power factor and the capacitor will not cause the transformer to tap to the extreme level. The capacitor banks should only be switched out of service if the zone substation has a leading power factor. This implies a switching controller based on VAr measurement of transformer summation. A dead-band should be programmed into the switching controller to minimise the amount of capacitor switching operations.

Local station loading may be sufficiently low at times to take the load beyond unity power factor into the leading region. This will unnecessarily increase losses and loading. Too much capacitance also can lead to voltage control problems on the upstream network, therefore operation of the zone substation should be as close to unity power factor as possible, preferably slightly lagging.

By optimising the pole top capacitor banks to the local feeder loads, the VAr controller at the zone substation will act to fill any shortfall in VAr supply for the zone substation.

The zone substation capacitor bank settings are located in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/ReactivePowerandVoltageRegulation/ZSS%20Capacitor%20Bank%20Settings>

## 6.7 Zone Substation Reinforcement

Augmentations of zone substations exceeding \$5m (direct costs) generally require the application of the RIT-D.

When the load in the area continues to grow it may be necessary to upgrade an existing zone substation. If the transformer thermal rating is the limiting factor, then the following options should be considered.

Augmenting a single transformer zone substation with a second transformer should be considered for inclusion in the Demand Strategy and Plan in the year the following conditions apply:

- Transfer capability is less than the station loading, or
- The cyclic rating is reached (under 10% PoE conditions).

Augmenting a two-transformer zone substation with a third transformer should be considered for inclusion in the Demand Strategy and Plan in the year the following conditions apply:

- Transfer capacity is insufficient to cover the load at risk, and
- The forecast station load exceeds the 2-hour emergency rating (under 10% PoE conditions).

Augmenting a two-transformer zone substation with sub-transmission line breakers or an automatic load shedding scheme should be considered for inclusion in the Demand Strategy and Plan in the year the following conditions apply:

- The forecast station load exceeds the 2-hour emergency rating, or
- The value of the energy at risk does not warrant the installation of a third transformer.

Individual justifications will need to be performed closer to the date before the projects are accepted by the business.

The sub-transmission loop rating should be checked to see if it is adequate for the new load.

At least two more feeders should be constructed out of the station if a new transformer is installed to utilise the additional transformer capacity and to improve feeder reliability performance in the area. The number of feeders per bus should be relatively balanced if possible, meaning one or more existing feeders may need to be relocated to the new bus.

Line breakers are not normally required on three-transformer zone substations as the 2-hour emergency rating is generally quite close to the nameplate rating of the station.

Where the loading on a zone substation is in excess of the (N-1) cyclic rating and it is uneconomic to upgrade the line or reconfigure the system, then the options of strengthening distribution feeders between two zone substations should be investigated to increase the load transfer capability or installing asset protection schemes (an automatic load shedding scheme) to prevent transformers being damaged due to excessive loading.

When a zone substation is planned to be upgraded, any changes on the existing Power Quality Analysers installed at the zone substation or installations of new Power Quality Analysers shall be enacted only after consultation with the Power Quality Engineer.

## 6.8 New Zone Substations

Establishment of new zone substations will require the application of the RIT-D.

The need for a new zone substation is identified during the process of developing the long term Demand Strategy and Plan. This process identifies emerging network constraints from long term maximum demand forecasts. The land purchase is then justified on the basis of this forecast need and combined with an options study for different site locations to target the optimum location at lowest cost. UE has always purchased land for future new zone substations a number of years before the zone substation is actually required and this is documented in the Land Acquisition Strategy [UE PL 2211](#) located in:-

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Plans/UE%20PL%202211%20Land%20Acquisition%20Strategy>

A detailed economic evaluation of the site is not undertaken until the time that the zone substation business case is developed, at which time the cost of the land is included in the cost of establishing the zone substation. This process provides greater certainty for UE to ensure land is available for development at the optimum time the zone substation is required rather than risking the project timeline due to a lack of available land. Given that land generally appreciates in metropolitan Melbourne, the risk to UE for an undeveloped zone substation site remaining undeveloped over a long period of time is regarded as negligible because the land should be able to be sold at a later time.

### 6.8.1 Site Selection

In selecting a suitable site for a new zone substation, a number of points should be critically evaluated including size, shape and nature of the block, access to the site and the position of the site relative to the load centre. Availability of sites and the demographics of the neighbourhood, especially in a built up area, can be a significant deciding factor in selection of a suitable site. The site selection criteria are detailed below.

The major consideration in the selection of a new zone substation site is that where possible it be located in the vicinity of the expected load centre. The expected future load distribution should be calculated by load predictions on the existing HV system and the likely problem areas highlighted. A spare capacity map will assist in providing this trend. Usually a compromise will need to be made between the available site positions and the electrical load centre.

The minimum size required for a new zone substation site is 3000m<sup>2</sup> to allow for adequate screening and vegetation around the site and the ultimate development of a three transformer station. This size will allow for construction of an indoor HV switchboard, outdoor transformers and outdoor 66kV switchyard.

Fully indoor substation sites may be as little as 1500m<sup>2</sup>.

Ideally the site should be rectangular in shape.

The site dimensions and location should be confirmed through a title search.

The land should be easily accessible by heavy vehicular transport for transportation of large equipment during construction and equipment deliveries throughout the life of the station (e.g. access for mobile transformer etc.)

Main roads should be avoided if possible to minimise interruption to traffic flows and risk of vehicle accidents.

Ease of access for sub-transmission lines and exit of HV feeders can significantly affect the total cost and can often be the deciding factor between alternative sites.

Zone substations are generally sited near an intersection to allow easy exit of feeders. Road and easement access, and future developments and zoning around the site may affect future feeder outlets and therefore affect the ultimate capacity and effectiveness of the station.

Easements for high voltage line access shall be secured prior to or at the time of the land purchase to ensure that lines can access the site.

The land should be well drained and not prone to flooding.

The land should be relatively flat to avoid significant civil costs to cut and fill the property to create a level platform for the zone substation.

The land should not contain significant rock content or formations to minimise civil costs.

The land should not contain fill or any material that would cause the zone substation to subside.

Prior to an offer being made for the site, the Section 32 documentation shall be reviewed to confirm the services available in the area including access to water, sewerage and telephone services.

The location of the site should consider potential environmental implications or contamination risk or liabilities.

Ideally tree clearing should be avoided and if necessary limited to exotic species only. Any tree clearing required will most likely require a planning permit. Where there is a risk of an impact to cultural heritage or to flora and fauna, UE should engage a consultant with expertise in these areas to provide a report for local council approval.

The site should avoid areas adjacent to local creeks and rivers to avoid potential run-off and contamination.

Site zoning preference is for industrial or commercial areas as this is expected to have the least community opposition. Further, a reduction in required underground cable lengths may be possible with industrial areas as overhead circuits are usually allowable on both sides of the road in industrial areas, whereas they are usually restricted to one side only in residential areas.

Residential zones are recommended only when industrial/commercial areas are not feasible due to a lack of available land, not central to the load centres or would result in significant cost increases in establishing a zone substation (e.g. lack of available sub-transmission infrastructure).

In any case, it is recommended to select a zoning where a Minor Utility Installation (i.e. the classification of zone substations under the planning schemes) is exempt from requiring planning approvals. This is detailed in the local government planning schemes.

Some zones have one or more planning overlays applied such as heritage, flora and fauna, or significant landscape. It is important to ensure that the proposed design of the zone substation does not violate the requirements of the planning overlays, otherwise a planning permit will need to be sought. The planning overlays are nominated in the Section 32 documentation.

Prior to an offer being made for the site, the Section 32 documentation shall be reviewed by UE's network planning and UE's legal counsel. Certain properties may contain restrictions, caveats and covenants which may limit the type and size of developments on a property. It is important to ensure that the proposed design of the zone substation conflict with the encumbrances.

The search for a site should consider potential objections from other properties surrounding the site.

### 6.8.2 Site Acquisition

The business case for the land purchase shall be a separate business case from the new zone substation business case. This is because the scope and cost of a new zone substation is unknown until after the land is secured.

The business case for site acquisition should describe and quantify the emerging network constraint and give the reasons why a site is required to be purchased. This will essentially be an abridged version of what would be included in a new zone substation business case.

The business case for site acquisition should also contain a detailed site assessment, listing all of the alternative sites considered (preferably two or more) and detailing what the advantages and disadvantages are of each site in relation to the site selection process detailed above. The lowest cost, most viable site that satisfies the selection criteria should be the preferred option. Where sites are comparable, the purchase of two sites may be warranted in some circumstances.

A detailed cost-benefit quantitative analysis is not required as the cost of the land should be included in the economic justification of the zone substation business case at a later point in time. If it is deemed that a zone substation is not required at a future point in time, then the land can be sold at that time, usually at a profit with no detriment to UE because land will generally appreciate in value.

The business case should be signed off for the full budget allocation including contingency, to allow some room to negotiate price during the procurement process. The UE capex delegated financial authority applies to the purchase of land for future zone substations.

All zone substation properties shall be purchased, not leased.

Once a suitable site is identified, it is recommended to get a market valuation undertaken. If this is within the business case allocation, it is recommended to purchase the site using a third party legal firm to approach the real estate agent anonymously. This will reduce the risk of the vendor escalating the price above market value.

It is required to involve the UE Environmental & Sustainability Manager and UE Legal Counsel in the land procurement process. Following procurement, the Manager Unitised Work shall be advised to ensure land is maintained while under the ownership of UE.



Land acquisition will lead the development of a new zone substation, sometimes by a number of years. It is UE's preference to secure land prior to developing the zone substation at least two years prior to signing off the zone substation business case because:-

- A 12 month lead time is now required for UE to undertake the regulatory test (RIT-D) process. This process requires UE to assess and quantify the economic cost and benefits of all viable options prior to committing to the development of a new zone substation. Unless a site has been secured, the economic costs and benefits for a new zone substation will not be known and therefore cannot be adequately assessed as a viable option in the regulatory test.
- Certainty is needed that a site is available for UE to be able to develop in the event that the need for the zone substation is brought forward by unforeseen demand growth. If a site cannot be acquired in time, UE may have to resort to suboptimal augmentation options.
- Availability of suitable land that meets the selection criteria is sometimes scarce, especially in built-up areas. If a suitable site comes onto the market, then there are no guarantees that the site will remain available on the market at the time the zone substation is needed. Most likely it would be sold and developed. Opportunities for an early purchase of a suitable site should be seized in such areas.

### 6.8.3 Development

Stations should be constructed with indoor 22kV or 11kV switch-rooms and outdoor 66kV switch-yards unless consultation with the residents in the local area or council recommend a fully indoor substation.

The station shall have a layout so that the view of the switchyard is concealed from the street and transformers should have adequate sound proofing depending on the location of the zone substation.

The zone substation must have sufficient space for connection of a relocatable transformer in the event of a transformer outage at the zone substation. Typically, the relocatable will require the space of two standard transformers.

All new stations shall have an NER to limit phase to ground fault level. Capacitor banks are no longer required at new zone substations unless it is not practical to install distribution feeder capacitors.

The station shall be designed for an ultimate layout of 3 transformers and 3 buses. The first stage of development shall be the middle transformer and bus. Stations shall be fully switched with sub-transmission line breakers only being mandatory for single transformer zone substations. These line breakers will become the bus-tie circuit breakers of the ultimate development.

A single transformer station is preferred over a two transformer station if the:

- Initial load planned to be transferred onto the new station is less than the nameplate rating, or
- Demand growth is low (less than 5% pa), or
- Transfer capability is higher than the expected station loading.

A new zone substation should be considered for inclusion in the Demand Strategy and Plan in the year the following conditions apply:

- Surrounding zone substations are loaded to at least the 2 hour emergency rating, and
- All surrounding zone substations have three transformers or are remote from the load centre, and
- Transfer capacity is insufficient to cover the load at risk.



## 7. Planning of Sub-Transmission

Sub-transmission Network Planning is undertaken by the Principal Engineer Network Planning. Capex programmes associated with this planning fall under the DO(A) activity code.

A sub-transmission line transports electricity from terminal stations to zone substations at sub-transmission voltages (typically 66kV and sometimes 22kV).

Generally two or more sub-transmission lines are used to supply zone substations in a sub-transmission network, in a loop or meshed arrangement. Sub-transmission lines have line circuit breakers at least at the terminal station and at single transformer zone substations to fully switch the line. In some circumstances line breakers may be provided at zone substations with two or more transformers where it can be economically justified to do so. For ring bus arrangements, there may be up to four or five sub-transmission line entries/exits into the zone substation, each sharing a circuit breaker with another network element.

UE's overall sub-transmission planning philosophy is to use a probabilistic risk assessment approach to determine the acceptable loading level of sub-transmission lines. In the past, the approach was to have sufficient capability such that for loss (planned or forced) of any single sub-transmission line during maximum demand, the voltages and loading on all remaining in-service elements would remain within their design limits/ratings for the duration of the outage. This (N-1) criterion is usually still applicable when a dynamic wind rating is used which provides some level of operating risk. The nature of the load and capital investment constraints may force significant compromises in the philosophy referred to above. Such compromises generally involve accepting more risk where load may have to be shed for single contingencies.

### 7.1 Sub-transmission Ratings

#### 7.1.1 Overhead Conductors

The standard conductors used for new 66kV sub transmission lines are:

	Size	Summer	Winter
<b>Preferred</b>	37/3.75 AAC (400mm <sup>2</sup> eq Al)	1,120A	1,195A
<b>Alternative</b>	19/4.75 AAC (331mm <sup>2</sup> eq Al)	980A	1,060A

Where summer and winter ratings correspond to the following design parameters:

Parameter	Winter	Summer
<b>Operating temperature</b>	100°C	100°C
<b>Ambient temperature</b>	10°C	40°C
<b>Circuit-to circuit differential temperature</b>	75°C	75°C
<b>Wind speed</b>	0.61 m/S	3 m/S
<b>Angle of wind to conductors</b>	90°	15°
<b>Time (day or night)</b>	Day	Day
<b>Environment (outdoor or indoor)</b>	Outdoor	outdoor

Direct solar radiation	1000W/m <sup>2</sup>	1000W/m <sup>2</sup>
Diffuse Solar Radiation	100W/m <sup>2</sup>	100W/m <sup>2</sup>
Conductor surface	Rural Weathered	Rural Weathered
Emissivity of conductor for rural weathered	0.5	0.5
Ground reflectance (albedo)	0.2	0.2

The model for overhead sub-transmission line rating calculation is located in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Ratings/Plant%20Ratings/Overhead%20Lines/Overhead%20Line%20Current%20Ratings%20Calculator.xls>

The conductor size is selected on the basis of initial load, load growth and the ultimate future load. The 37/3.75AAC is used extensively in urban areas. Depending on the economics, 19/4.75AAC may be used in preference to 37/3.75AAC if the load growth is such that the smaller size conductors are assessed to be suitable for the longer term (e.g. 20 years) and hence more economic.

In all other instances 37/3.75AAC is recommended as this will allow operations of two 22kV zone substations on the same loop (one 3 transformer station and one 2 transformer station) within the rating of the loop. If both stations are ultimately developed to 3 transformers, a third teed line may be constructed between the terminal station and the line between the two zone substations.

A 66kV line built today would usually be designed to run at a maximum temperature of 100°C. Older lines may have a lesser maximum but these ratings should be upgraded to 100°C operating as loadings increase.

New sub-transmission sections on the terminal station legs of the loop should be capable of operating at or below (N-1) summer rating with the full load of all zone substations in the loop operating at the 2 hour emergency rating.

Sub-transmission sections between zone substations can be rated at lower values as they are not required to carry the full loop loading, but the loading of only some of the stations.

### 7.1.2 Underground Cables

The high cost of 66kV underground cable prohibits its use unless it is impossible to construct an overhead line. However, underground sub-transmission is sometimes used when the sub-transmission enters a zone substation either due to access or aesthetic issues.

For any new sub-transmission on the terminal station legs of the loop, the cable rating should at least match the rating of the highest rated overhead section of the line.

### 7.1.3 Overall Sub-transmission System Rating

The overall rating of a looped or meshed sub-transmission network depends on the loading at zone substations on the system, the share of flows down each line of the system and the individual line ratings. The (N) rating applied with all lines in service, and the (N-1) rating is the lowest rating with any single line in the sub-transmission system out of service.

Sub-transmission ratings are specified in Amperes.

For all sub-transmission topologies, the process to calculate the N-1 rating requires the use of the software PSS/E. An example is shown below for the MTS-EM-EL-CFD-MTS 66kV loop.

The values in the first table below were obtained from PSS/E for system normal and contingency analysis (loadings when a line is taken out of service).

	Loading	Loadings when line OOS					Summer Overload Level					Summer Loop	
Sub-t Line	Normal	MTS-CFD	tee	CFD-EL	MTS-EM		Normal	MTS-CFD	tee	CFD-EL	MTS-EM	N	N-1
MTS-CFD	318		671	385	345		38%	0%	81%	46%	42%	2498	1184
CFD-EL	68	393	283		48		8%	47%	34%	0%	6%	11681	2021
EL-tee	337	669		274	311		41%	81%	0%	33%	37%	2357	1187
MTS-tee	275	446		243	596		25%	40%	0%	22%	53%	3898	1798
MTS-EM	346	506	286	316			39%	58%	33%	36%	0%	2434	1664
EM-tee	62	222		31	287		7%	27%	0%	4%	35%	12811	2768
TOTAL	939	952	957	944	941								

Next, each of these load values are divided by the corresponding rating of the line section (obtained from Circuit Data Sheets) to give a percentage utilisation value shown in the second table. The maximum value of the total loading in the sub-transmission system (sum of all flows out of the terminal station) shown in the bottom table is then divided by the 'Normal' percentage above to give the 'N' values in the third table or divided by the maximum percentage of each of the contingency analysis rows to give the 'N-1' values in the third table.

Finally the minimum value of each of the (N) and (N-1) columns in the third table is taken to find the overall (N) and (N-1) ratings of the sub-transmission system, in this case, 2434A for the (N) rating and 1184A for the (N-1) rating.

The same method is used for calculating the winter ratings using the line section ratings from the Circuit Data Sheets.

OVERALL N-1 SUB-T LOOP RATING		
	Rating (A)	Limit
Summer	1184	MTS-CFD
Winter	1234	MTS-CFD
OVERALL N SUB-T LOOP RATING		
	Rating (A)	Limit
Summer	2357	EL-tee
Winter	2456	EL-tee

The ratings may change over time due to changes in line flows on the sub-transmission system with changes in zone substation demand.

This model is located in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Ratings/Subtransmission>

## 7.1.4 Dynamic Wind Ratings

Under certain conditions, the dynamic wind speed rating may need to be utilised in maximise capability of a sub-transmission line.

Statistics show that in summer, on hot days when the load is very high, there is a greater than 99% chance that the wind speed will be above 0.61m/s. Under these conditions the cooling effect on the conductors is quite significant and substantial increases in loop rating can be achieved, therefore reducing the risk significantly. The direction of the wind however has an impact on the increase in rating, with the relevant wind vector being perpendicular to the conductor.

For a 37/3.75AAC conductor, its summer rating at 2m/s wind speed perpendicular to its axis is 1250 Ampere (143MVA at 66kV) for operation at 100°C. This rating will typically support a three transformer and a two transformer zone substations operating at their 2 hour emergency ratings.

Dynamic ratings is currently only implemented in the "Loadings and Ratings Database" which varies the sub-transmission line rating between the summer and winter ratings taking into account actual ambient temperature. In future, to take into account the effects of wind, the dynamic rating function is best implement in the DMS.

## 7.2 Sub-transmission Loop Arrangement

Zone substations are supplied from at least two sub-transmission lines on diverse routes. The protection associated with each line should also be independent of the protection of the other line.

New sub-transmission systems must be in a loop or meshed arrangement at 66kV. More than one zone substation can be included in a sub-transmission system.

Each leg of a sub-transmission system should be placed as far away from the other legs as practically and economically feasible. The closest point between two legs of the loop should be at the zone substations themselves. This is to minimise the risk of a double contingency taking out of service the entire zone substation(s).

Double circuit sub-transmission is allowable as long as the two circuits are not a part of the same loop or the loss of both circuits does not result in widespread load shedding.

## 7.3 Sub-transmission System Reinforcement

Augmentations of sub-transmission systems exceeding \$5m (direct costs) generally require the application of the RIT-D.

All sub-transmission lines shall have auto-reclose enabled (where possible) to minimise the risk of load shedding in the event that the loop loading is greater than the (N-1) rating. This relies on the fact that the majority of faults on sub-transmission lines are transient in nature and can be cleared by an auto-reclose.

For sub-transmission lines that are limited in capability by droppers, the droppers should be upgraded when the sub-transmission system loading exceeds the (N-1) rating.

For loops that are limited in capability by the conductor, the upgrade should be indicated in the Demand Strategy and Plan in the year the following conditions apply:

- The forecast load on any line section exceeds the (N) rating of the line section with all lines in service, or
- The total loop load exceeds the (N-1) loop rating by more than the transfer capability away from the stations on the loop to other stations.

The timing of sub-transmission augmentations will be strongly dependent on the temperature sensitivity of the load and the cost of the proposed augmentation.

Where the loading on a sub-transmission loop is in excess of the (N-1) rating and it is uneconomic to upgrade the line or reconfigure the system, then the options of thermal uprate to increase the capability or strengthened distribution feeders between two loops to increase the load transfer capability, should be investigated.

Where the loading on a subtransmission loop causes a voltage collapse situation under a single contingency, then the load shall be limited precontingent so as not to create a voltage collapse situation.

## 7.4 Circuit Data Sheets

The Circuit Data Sheets (CDS) contain sub-transmission information regarding:

- Circuit route;
- Conductor types of each section and lengths;
- Clearances and construction type;
- Ratings;
- Impedances;
- Limiting equipment at each end of the line.

This information needs to be updated by the Service Provider in consultation with Network Planning whenever a change is made to the sub-transmission network. Changes are to be forwarded onto the GIS Services team for updating of the sheets in AutoCAD.

The system area diagram UE6/306/004 should also be reviewed and updated whenever there is a change to the sub-transmission network.

Hand written changes on the data sheets are not a permanent solution and if done should be accompanied by a signature and date and marked up in red pen. An updated hardcopy of the circuit data sheet should be requested as soon as possible once a change has occurred to minimise any ambiguities. AMFM-GIS should be updated by the GIS Services team when updating the sheets.

A model is used by the Senior Engineer Network Planning to calculate line impedances and ratings for the Circuit Data Sheets. The Circuit Data Sheets impedance and rating calculation model is stored in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Ratings/Subtransmission/Circuit%20Data%20Sheets.xls>

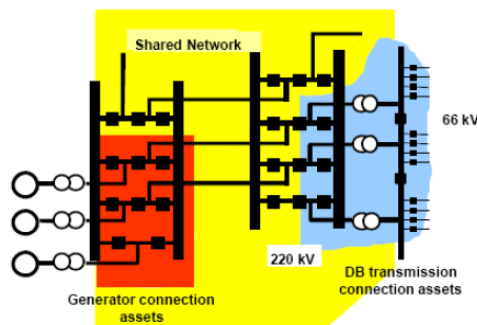
## 8. Planning of Transmission Connection Assets

Transmission connection asset planning is undertaken by the Principal Engineer Network Planning as a joint exercise with peers in the other Victorian Distribution Network Service Providers (DNSP), and the Australian Energy Market Operator (AEMO) in its role as planner for the Victorian declared shared transmission network.

Transmission connection assets are those parts of the transmission system which are dedicated to the connection of customers at a single point. In Victoria:

- the DNSPs have responsibility for planning and directing the augmentation of the facilities that connect their distribution systems to the Victorian shared transmission network; and
- AEMO is responsible for planning and directing the augmentation of the shared transmission network.

Transmission connection assets are generally a subset of a terminal station, providing a point of connection for UE's sub-transmission lines. Transmission connection assets usually comprise of sub-transmission level line circuit breakers, busbars and transformers, converting transmission level voltages (typically 220kV) to sub-transmission or distribution voltages (either 66kV or 22kV).



In Terminal Stations with 220/22kV or 66/22kV transformation, 22kV circuit breakers that supply sub-transmission lines (e.g. MTS BW and MTS-SH 22kV lines) are treated as connection assets. However, the 22kV circuit breakers that supply customer load directly (e.g. Vic Rail feeders at MTS and RWT13) or distribution feeders (e.g. RWT12, RWT23, RWT24, RWT34 and RWT35) are defined as distribution assets.

Whilst these transmission connection assets are owned by a Transmission Network Service Provider (TNSP), typically AusNet Transmission Group in Victoria, it is UE's responsibility to plan the augmentation of the connection assets at UE's points of connection to the transmission network. If the connection assets are shared with other distribution businesses then the planning for the connection assets should be undertaken jointly. The Principal Engineer Network Planning must communicate with the peers in the other distribution businesses and indicate intentions for planned augmentations at terminal stations. Significant load transfers to or from a terminal station should also be communicated with the other distribution businesses so they are able to re-assess their risk and augmentation plans. This communication needs to be two-way approach to provide a clear planning strategy for the connection assets and to minimise potential tangents in planning between the different distribution businesses.

AEMO and the DNSPs undertake joint planning to ensure the efficient development of the shared transmission and distribution networks and the transmission connection facilities. To formalise these arrangements, the parties have agreed a Memorandum of Understanding (MoU). The MoU sets out a framework for cooperation and liaison between AEMO and the DNSPs with regard to the joint planning of the shared network and connection assets in Victoria. The MoU sets out the approach to be applied by AEMO and the DNSPs in the assessment of options to address limitations in a distribution network where one of the options consists of investment in dual function assets or transmission investment, including connection assets and shared transmission network. Under the MoU, the DNSPs have agreed that joint planning projects should be assessed by applying the RIT-T in accordance with clause 5.16 of the NER. The MOU is located in

<http://uenetwork.domain.prd.int/CustomerandConnections/TransmissionConnectionAssets/AEMO%20MoU>

## 8.1 Connection Asset Ratings

Ratings for transmission connection assets are provided by AusNet Transmission Group through the OSSCA Schedules (station capability and transformer summation capability) and through the RADAR database (feeder exit capabilities). The OSSCA Schedules are sent from AusNet Transmission Group Operations to the UE NCC annually, just prior to summer and are stored in

<http://uenetwork.domain.prd.int/RiskAndEmergency/ContingencyPlans/UE%20MA%202204%20Contingency%20Plans/Background/OSSCA%20Settings>

The RADAR information can be obtained from <https://xra.sp-ausnet.com.au/> using the RSA Security ID token.

## 8.2 Contingency Schemes

Given UE is responsible for planning the transmission connection assets and ownership lies with AusNet Transmission Group, UE's probabilistic risk approach to operating assets is inconsistent with AusNet Transmission Group's no risk approach of operating assets. To manage this issue, AusNet Transmission Group operates control schemes to trip load in the event of an asset overload. When connection assets are shared with other DNSPs, the load shedding is shared between the distribution businesses taking supply from the station in accordance to the share of the total load being taken.

OSSCA (Overload Shedding Scheme for Connection Assets) is a scheme implemented to protect connection assets from overload. If the connection assets are operating above the (N-1) rating and a contingency occurs, pre-defined sub-transmission loops will be shed to bring the station back to a safe loading level.

At shared terminal stations, the stations included for load shedding should be shared between the distribution businesses taking supply from the station in accordance to the level of load being taken, but taking into account the criticality of the load being shed. These load shedding blocks need to be agreed between DNSPs and VEEC.

SOCS is a transmission line load monitoring system. It assesses the dynamic rating of the line depending on weather conditions and provides a short term forecast of future loading levels based on thermal time constants. SOCS has been enhanced to include actual real-time wind speed recordings into the algorithm.

Under conditions where there is a generation shortfall, UE may be called upon to shed load to maintain system security on the transmission network. Feeders need to be listed in order of shedding based on how critical the load is on each feeder. This list is managed by the UE NCC and a copy is stored in

<http://uenetwork.domain.prd.int/RiskAndEmergency/ContingencyPlans/UE%20MA%202204%20Contingency%20Plans/Background/Load%20Shedding%20List>

## 8.3 Setting Voltage Levels at Terminal Stations

On or before the 15<sup>th</sup> May each year, each DNSP shall advise AEMO of the voltage set point requirements at each terminal station. Where terminal stations are shared between DNSP, the set-point shall be determined in consultation with each DNSP and should ensure zone substation transformers operate within a desirable tapping range. The location of the terminal station voltage set-points is in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/ReactivePowerandVoltageRegulation/Voltage%20Regulation%20Settings/Terminal%20Station>

## 8.4 Sub-transmission Emergency Ties

Many of the transmission connection assets supplying UE's service area operate with some level of load above (N-1) and are therefore subject to OSSCA operations. Furthermore, many of the transmission connection assets supplying UE's service area are supplied from radial double circuit 220kV transmission lines. Therefore failure of a connection asset or loss of supply to a connection asset can result in widespread loss of supply to UE's customers.

As such UE has developed a number of normally open sub-transmission tie lines connected between terminal stations to provide sub-transmission load transfer capability. A manually operated tie switch or open bridge is provided to enact the transfers. During emergency load transfers, UE's sub-transmission assets are operated radially to simplify the protection requirements.



The list of sub-transmission emergency tie lines and the instructions for enacting these emergency ties are documented in [UE PR 2214](#) and located in

<http://uenetwork.domain.prd.int/RiskAndEmergency/ContingencyPlans/UE%20PR%202214%20Subtransmission%20Emergency%20Ties>

## 8.5 Terminal Station Reinforcement

Augmentations of terminal stations exceeding \$10m generally require the application of the RIT-T and this may need to be done jointly with other DNSPs and/or AEMO. These types of projects generally capture all new transformer projects. Lower value projects generally involve the establishment of new sub-transmission feeder exits and these do not require the RIT-T.

Terminal stations are generally designed to allow three transformers to operate in parallel. Standard sizes are 150MVA and 225MVA for 220/66kV transformers.

If space exists for the addition of a fourth transformer, two bus groups should be established to manage fault level with a normally open circuit breaker between the two groups to allow an auto-close scheme to join the two bus groups in the event of a transformer outage.

If space exists for the addition of a fifth transformer, two bus groups should be established to manage fault level with a normally open and normally closed circuit breaker on the fifth transformer to allow an auto-changeover scheme to transfer the fifth transformer across from one bus group to the other in the event of a transformer outage.

In all cases, all transformers at the terminal station should be normally on-load.

A lead time of two years is required for augmentation of a terminal station involving a transformer, or up to 18 months for all other projects.

Determining the optimum time for a terminal station augmentation is a complicated process and requires significant risk assessment studies.

This should be based on:

- Number of times per year the station is operating above (N-1)
- The amount of load at risk compared with the transfer capability
- Loading of the station in respect to the (N) rating
- Load growth
- Other deferment options such as load transfers or power factor correction

If augmentation of a terminal station with another transformer would lead to the eventual overloading of the upstream transmission network, then consideration should be made to establishing a new transformer or new terminal station at another site where there is spare transmission network capacity.

## 8.6 Establishment of New Terminal Stations

Establishment of terminal stations will require the application of the RIT-T and this may need to be done jointly with other DNSPs and/or AEMO. It is preferable to establish new terminal stations on existing reserved sites with good access to the existing transmission network. Where this is not possible, joint planning will be required with AEMO to secure a site and appropriate transmission easements. New terminal stations shall be established with a minimum of two transformers. The size of the transformers shall be selected to meet the long term growth projections of the supply area.

A new terminal station should be considered for inclusion in the Demand Strategy and Plan in the year the following conditions apply:

- Surrounding terminal substations are loaded to at least the emergency (N-1) rating, and
- All surrounding terminal stations have three transformers or are remote from the load centre, and



- Sub-transmission networks supplied from the existing terminal substations are loaded to at least the (N-1) rating, and
- Transfer capacity is insufficient to cover the load at risk.

A lead time of five years will be required for a new terminal station and will most likely involve other distribution businesses. If new transmission lines are required, then the lead time may be up to ten years, especially if easements need to be acquired by AEMO.

## 8.7 Augmentation of Transmission System

While augmentation and establishment of new declared shared transmission equipment is an AEMO responsibility, UE should work closely with and influence AEMO to ensure that the transmission plans and developments are consistent with UE's long term network plan.

## 9. Network Augmentation Needs Due To CIC Projects

Customer Initiated Capital (CIC) is the electricity network capital expenditure related to establishing new connections, or modifying or extending the existing UE electricity network, to accommodate customers' demand needs. CIC projects are initiated and carried out upon customer requests through the customer connection process which is governed by the UE Distribution Customer Connection Guide (<https://www.unitedenergy.com.au/your-electricity/new-connections/>) and regulatory obligations.

Typically, works related with a customer connection are three-fold.

- Building connection assets at the customer premises
- Modifying the existing network or building additional network as required
- Connecting connection assets to the network

Depending on the size of the customer connection and status of the network assets in the area, some upstream network augmentations will be required to accommodate the new load. Some of these network augmentation works are to be undertaken through the CIC project in cases when the need for the augmentation is clearly triggered by the connection of the customer. Such instances are discussed in detail below.

Before implementing any network augmentation, the CIC Project Planner shall consult UE Network Planning at [planning@ue.com.au](mailto:planning@ue.com.au) to determine the appropriate arrangements.

### 9.1 Installation of new or upgraded distribution transformers

In the event that the existing local LV circuit conductors, LV fuses and distribution transformers in the area of the new connection have sufficient spare capacity to absorb the new customer's immediate load requirements, and where the voltage drop and protection reach requirements are satisfied; then installation of new distribution transformer is not warranted. New transformers for the area will be considered in future as part of the DSS programme.

When assessing the distribution substation capacity, the cyclic rating of the transformer, not the nameplate rating, should be considered. Typically, loading a substation to 120% of its cyclic rating is considered acceptable when assessing new connections.

#### 9.1.1 Peak Demand

Peak demand of existing substations can be obtained from Network Load Management (NLM) Tool using the "Network Peak Load" report. NLM calculates the peak demand dynamically by aggregating UE customer demands that are connected to each distribution transformer. Where a new connection is to be made to an existing cross-border substation (i.e. those substation supplying UE customers as well as AusNet Services or CitiPower customers), then peak demand of other distributor's customers should also be considered.

#### 9.1.2 Cyclic Rating

Cyclic rating of distribution transformers are calculated using a number of variables including the type of transformer, nameplate rating, operational conditions such as load profile, ambient temperature etc. The NLM Tool also calculates the cyclic rating of each distribution transformer dynamically, which can be obtained using the "TLM Analysis and Consolidated Project List" report. Given this report is undergoing significant enhancement, the cyclic ratings from this report should not be used until further notice. Instead, the cyclic ratings below shall be adopted.

Type	Nameplate Rating	Load Type	Summer Rating (kVA)	Winter Rating (kVA)
Pole	100	Residential	118	144
		Commercial / Industrial	111	127
	200	Residential	236	289
		Commercial / Industrial	222	254
	315	Residential	372	455
		Commercial / Industrial	350	400
	500	Residential	591	722
		Commercial / Industrial	555	635
	315	Commercial	322	384
Indoor	500	Commercial	511	610
	750	Commercial	729	875
	1000	Commercial	972	1166
	1500	Commercial	1386	1665
	2000	Commercial	1848	2220
Ground	315	Commercial / Industrial	350	400
	500	Commercial / Industrial	555	635
	750	Commercial / Industrial	793	900
	1000	Commercial / Industrial	1058	1201
	1500	Commercial / Industrial	1515	1716
	2000	Commercial / Industrial	2020	2288
Kiosk	315	Residential	337	432
	500	Residential	536	685
		Commercial / Industrial	505	600
	750	Commercial / Industrial	729	858
	1000	Commercial / Industrial	971	1144
	1500	Commercial / Industrial	1457	1716
	2000	Commercial / Industrial	1943	2288

## 9.2 Installation of additional switches to create new zones

UE Distribution Switch Application Guidelines provide directions in relation to the amount of installed capacity that can be accommodated in a high-voltage switch zone. These limitations are to ensure network reliability and operational flexibility in the event of an outage. If a new customer connection will exceed the recommended maximum capacity within a given switch zone, then a new switch will be required to split the existing switch zone. Occasionally, this may require installation of a new pole or replacement of an existing pole. The works associated with creating new switch zones shall be undertaken through the CIC project.

If the cost of creating a new switch zone is prohibitively expensive (especially when a pole replacement or a new pole is required), the impact of not creating that new switch zone needs to be considered. If that work is not critical to manage the reliability and operational flexibility of the network, larger switch zones outside the Switch Application Guidelines will be acceptable. The CIC Project Planner shall consult UE Network Planning in such instances for guidance.

Opportunistic replacement of isolators with gas-insulated switches should not be classified under CIC unless by not doing so, it violates the UE Distribution Switch Application Guidelines.

## 9.3 Reconductoring of primary spurs

If the new load is to be connected to an existing spur and augmentation of the spur (either reconductoring or replacement of underground cable) is required because the connection will cause the spur to exceed 100% of its capacity, such work shall be undertaken through the CIC project. This may include decommissioning or relocation of the existing spur fuse and installation of new switches.

## 9.4 Reconductoring for establishing backup lines

Large industrial, commercial and residential developments and estates (which may develop in stages over time) usually require multiple in-feeds to secure the supply. In certain instances, such large developments will need to be looped into an adjacent feeder to provide backup supply in the event of an outage of the primary feeder.

If the backup connection is to be made on to an existing spur, the capability of that spur shall be reviewed. If capacity of the spur is insufficient, augmentation of the spur shall be undertaken as part of the CIC project. This may include reconductoring of overhead lines, replacement of cables, decommissioning of fuses and installation of new switches.

For works on the backup line to be classified as CIC, the backup line works shall not increase the total cost of connecting the development / estate by more than 40%. Otherwise it shall be considered for a Demand Capex project.

## 9.5 Reconductoring of backbone sections

As part of Network Planning, under-rated backbone sections of feeders are regularly augmented to match the organic demand growth. Given the historical developments and demand spread of the feeders, all the backbone sections might not be constructed to the same capacity.

In cases where the connection will cause the backbone section to exceed 100% of its capacity, augmentation work shall be undertaken as part of the CIC project.

This situation is common when a large load is connected to an end of a feeder or to a feeder with split backbones.

## 9.6 Conversion of voltage

When a new large load is to be connected at a boundary of either 11kV/22kV or 6.6kV/22kV, connecting it at a higher voltage (22kV) may be advantageous based on capacity point of view. However, this depends on the available spare capacity of both the feeders and the relevant zone substations too. In certain circumstances, this may involve conversion of part of the existing assets to a higher voltage. The CIC Project Planner shall consider such possibilities in case by case basis and consult Network Planning for further advice. Such connections and conversions (where deemed necessary) shall be undertaken through the CIC project.

## 9.7 Opportunistic augmentations

There are instances where undertaking additional network augmentations are deemed beneficial together with a CIC project even though such works is not directly related to the intended connection. The CIC Project Planner shall consult UE Network Planning for further advice when such possibility exists. Four of such scenarios are discussed below.

However, using CIC Capex for opportunistic augmentations shall be minimised and such works shall be carried out only if they are absolutely necessary or deemed to be overly expensive to implement as a separate project.

### 9.7.1 Three-phase conversions

This is a common scenario in LV networks where supply is single-phase. If a new customer asks for a three-phase supply in such area, it will need to convert part of the network to three-phase. Given the locality of the network, it may be more beneficial to convert the rest of the LV network to three-phase too and balance the load. The CIC project planner shall consult UE Network Planning when such possibility exists.

If such additional works is deemed prudent, it shall be undertaken through the CIC project.

### 9.7.2 Conversion of existing SWER systems

Most of the existing SWER isolation transformers operate at or above their thermal capacities and do not have spare capacity to support new loads. If a new customer or an existing customer ask for additional supply in such area, it will need to either augment the existing SWER network, convert part of the SWER network to single/three-phase or connect the new load to an adjacent single/three phase supply. Augmentation or extension of the existing SWER networks is typically discouraged as long as practically and economically viable alternative is available due to inherent issues associated with the SWER network. The CIC project planner shall consult UE Network Planning when such possibility exists.

If such additional works is deemed prudent, it shall be undertaken through the CIC project.

### 9.7.3 Undergrounding

If a small section of overhead line exists between underground cables, it may adversely affect the performance of the surge arresters as a result of reflective waves in the event of a lightning strike. If a new load is to be connected to such small overhead section exists among underground cables, it will be prudent to convert the overhead section into underground cable. The CIC project planner shall consult UE Network Planning when such possibility exists.

In such scenario, the works shall be undertakes through the CIC project.

### 9.7.4 Provision for future expansions

In a broader perspective, there can be a need to expand the distribution network in an area where a CIC project is planned to be undertaken. If keeping provision for future network expansion at the substation (e.g. installing an IFT instead of a ring kiosk) is deemed prudent, such works shall be included into the CIC project. This type of opportunistic provisions shall be treated in case by case basis and Project Planners shall liaise with the Principal Engineer Network Planning to identify whether any such need exists.

If network development needs are not considered in CIC projects and appropriate provisions are not kept, it will hinder the operational flexibility of the network in the long run and; prevent managing and expanding the network in a sustainable manner.

## 9.8 Unidentified large spot loads in the demand forecast

As part of the demand forecasting process by Network Planning, attempts are made to collate prospective new load connections and to provide appropriate allocation for identified new growth. Augmentation needs are identified in advance and demand related projects can be created in the Asset Management Plan (AMP) so that appropriate budgets are allocated for the network augmentation work. Presently, all new connections above 100A are forwarded for approval by the Principal Engineers Network Planning. This is to ensure that appropriate LCTA solutions are identified by the Service Provider Project Planners.

However, not all the prospective projects are identified in advance so that necessary provisions are made to accommodate the new demand. Given UE has a regulatory obligation to allow customers to connect to the network in a timely manner, UE

cannot unreasonably delay customer connections until demand related project is created in AMP to undertake necessary network augmentations. In such scenario, augmentation work shall be undertaken through the CIC project.

## 9.9 Staged developments

Some of the larger projects are implemented in stages and timing of those stages is not always certain. However, the ultimate supply arrangement to the overall development shall be considered at the beginning of the project. If new feeders or augmentation of existing feeders are required to provide the ultimate development, it shall be captured in the CIC project. Subsequently, the CIC project can be segregated to stages during implementation depending on the progress of the development.

## 10. Forecasting

### 10.1 Maximum Demand Forecasting

Maximum demand forecasting is undertaken by the Principal Engineer Network Planning. Maximum demand forecasting aids determination of the need and timing for network augmentation and is a key input into the asset management planning process.

This section outlines the processes for determining the rate of load growth, the assessment of maximum demand and the steps involved in the preparation of the maximum demand estimates for the Demand Strategy and Plan.

#### 10.1.1 Data Collation

Prior to commencing the maximum demand forecast, a significant amount of data needs to be acquired. At the transmission points of connection, this information is obtained from the interval metering data using the boundary meter NMIs listed in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/BoundaryMetering/Boundary%20Load/UE%20Boundary%20Load%20NMIs.xls>

For the distribution network, OSI-PI stores all of the SCADA historical data.

These data capture systems should be checked regularly for data integrity during the monitoring period.

The Network Loading Reports (NLR) are also used as a basis for identifying high demand days and for providing high level information on asset loading. The reports are located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Reports/Network%20Loading%20Report%20NLR>

If it is known that the SCADA system will not be logging on a potential day of maximum demand, then the Principal Engineer Network Planning should notify the NCC of the zone substations to be manually logged by an operator and the time of day at which this is required. Priority of stations is highest utilised stations first. The Network Intelligence team should also be notified if the quality or availability of SCADA data being stored in OSI-PI is inadequate.

If loading data is not available or only partly available at the time of maximum demand then some estimation will need to be done. The estimated figure should be based on the data available from other sources such as IMS, or loadings at surrounding zone substation, or derived through calculation using other quantities. The estimated figure should then be confirmed with forecasts and high demands on other days during the season.

#### 10.1.2 Probability of Exceedance (PoE)

UE's maximum demand has a strong correlation with average daily temperature, that is, the average of the daily maximum temperature and the previous overnight minimum temperature. From a baseline perspective, this average temperature historically refers to the Melbourne Regional Office (086071) weather station on the <http://www.bom.gov.au/climate/data/> internet site, but from 2015 this has been changed to Melbourne Olympic Park (086338). The average temperature profile has a skewed probability distribution and the particular values of the average daily temperatures that correspond to a 10%, 50% and 90% probability of exceedance over the most recent 50 years of historical temperature data are used as the basis to determine the corresponding maximum demand forecasts.

#### 10.1.3 Weather Correction

The process of adjusting an actual maximum demand for an average temperature condition to the maximum demand that would have occurred on that day under a different average temperature condition is known as weather correction. Usually the actual maximum demand is weather corrected to one of the 10%, 50% or 90% average temperature conditions to allow a direct comparison between the weather corrected actual and the forecast maximum demand for that year. The same average temperature probability distribution that defines the average temperature for each of the probabilities of exceedance is used in the weather correction process.

UE's detailed procedure for undertaking weather correction of the asset loading is provided in the Maximum Demand Forecasting Method [UE PR 2200](#) located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Procedures/UE%20PR%202200%20Maximum%20Demand%20Forecasting%20Method>

#### 10.1.4 United Energy (UE) Network

UE service area maximum demand growth forecasts are determined using a top-down approach by the independent external consultant NIEIR (National Institute for Economic and Industry Research). A high, medium and low economic growth forecast is developed for maximum demand at 10%, 50% and 90% probability of exceedance levels. These forecasts are based on regional economic growth forecasts for the UE geographic area in its entirety. NIEIR also produces maximum demand forecasts for UE load at each terminal station. The UE maximum demand represents the maximum of the average demand over any half hour period.

NIEIR has developed a method for modelling and forecasting summer and winter peak demands utilising a combination of regression methods and Monte Carlo simulation. The model developed by NIEIR is known as PeakSim. UE engaged AECOM to develop a model using the eViews software which operates in a similar manner to the PeakSim model and is used to verify the NIEIR PeakSim model. The UE model which was developed by AECOM is located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Models/AECOM%20Demand%20Forecast>

The NIEIR PeakSim model has evolved out a number of lines of research at NIEIR. The key initial research began several years ago with a request to provide greater information about the probabilistic nature of seasonal maximum demands. This research pulled together earlier work undertaken by NIEIR in the 1990s and work done by various planning bodies in Australia and around the world. The PeakSim model generates probability distributions of peak demand from synthetically generated distributions of temperature and demand. This contrasts with more deterministic models that conditions peak demand forecasts on given temperature levels. A key driver of PeakSim's probabilistic projections is growth in temperature sensitive load which is primarily driven by air conditioning sales. National Economics monitors and forecasts air conditioner sales and this information is incorporated into the PeakSim model. The PeakSim model uses half-hourly demand and temperature data, (ideally) spanning at least 10 years. Each half-hourly period during the day is modelled separately to capture the intra-daily dynamics between demand and temperature. Temperature insensitive load is modelled using economic and industrial indicators. Synthetic distributions of demand for each half hour period are generated from the estimated models using synthetically-generated temperature and residual series. Synthetic temperature series are generated from historical temperature data using sampling methods that preserve the observed patterns in the historical data and allow for the effects of urban and global warming on recent and future climatic conditions. Similarly, synthetic residuals series are generated using sampling methods that ensure consistency with the model structure and the historical events. The PeakSim model outputs thousands of synthetic demands for each half hour period over each forecasted season. Probability of exceedance levels are drawn directly from this simulated data. In addition to the conventional metrics of 10%, 50% and 90% probability of exceedance levels, the PeakSim model can generate projections for the full probability spectrum. The PeakSim model also incorporates the impact of Federal and State Government's energy and environmental policies on demand. The model incorporates the impacts on energy prices from policy measures.

For the summer MD, which typically occurs at 4:00 or 4:30 p.m. (summer time) on a weekday in February in Victoria, the temperature sensitive load or additional demand is unambiguously associated with cooling appliances such as air conditioners, refrigeration units and fans. For the winter MD, which typically occurs at 6:00 p.m. or 6:30 p.m. in June or July, the temperature sensitive load is associated with primary and secondary electrical heating load. In the case of winter, however, the additional electricity load is not unambiguously associated with space heating load since utilisation of other electrical end-uses such as lighting, cooking appliances and entertainment appliances would also increase at this time of day. NIEIR's approach is to calculate the probabilities associated with different average daily temperatures in each season. The average temperature was defined as the arithmetic average of the overnight minimum and the daily maximum. These probabilities are based on both weekday and weekend temperatures. Summer is defined to include November to March but excluding public holidays and 20 December to 20 January in each year, and winter is defined as June, July and August, excluding public holidays.

The NIEIR maximum demand forecasts, their analysis report and the supporting input data is stored in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/MaximumDemandForecasts/UE%20Forecasts>

UE's maximum demand forecasting approach uses the NIEIR UE service area medium growth 10% PoE forecast as the basis for which the diversified, summated bottom up zone substation maximum demand forecasts (developed internally by UE Network Planning) must equal. The medium (most probable) economic growth scenario with a 10% probability of



exceedance (1 in 10 years) with due regards to energy policies of federal and state governments is chosen as the basis for projecting constraints.

Given summer maximum demand is the main driver for augmentation capex on the UE network, UE verifies and reconciles the NIEIR Summer Maximum Demand forecast by:

- Weather correcting the actual maximum demands and comparing them with the NIEIR forecast for that year; and
- Developing a bottom-up forecast by aggregating zone substation forecast and taking into account diversity, cross-boundary transfers and sub-transmission losses, then comparing this with the latest NIEIR forecast for that year; and
- Using a model developed for UE by AECOM in the eViews software that allows an internally generated maximum demand forecast for the UE service area.

If the error in any one of the above verification methods exceeds 5%, then UE should raise this discrepancy with NIEIR for further investigation until the source of the discrepancy is identified and resolved.

If the error is within this margin, then the NIEIR forecast remains unadjusted and all bottom-up forecasts developed by UE are scaled to match the NIEIR total UE service area forecast maximum demand as part of the reconciliation.

A summary of all historical and forecast UE maximum summer and winter demand, calendar year and financial year energy sales and purchases, and customer number data is located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/MaximumDemandForecasts/UE%20Forecasts/UE%20Actual%20and%20Forecast%20Demand%20Energy%20Customer%20No.xls>

This spread-sheet also has the weather correction calculations for the UE summer maximum demand.

### 10.1.5 Transmission Points of Connection

Transmission connection asset forecasts are developed after the zone substation forecasts are completed.

UE is required to prepare for AEMO, transmission connection asset maximum demand forecasts for summer and winter. Once the forecasts are developed, they are populated in AEMO templates and submitted to AEMO in July each year.

Connection asset forecasts developed by UE are for the UE component of load at the terminal station only, for summer and winter and are developed from the bottom-up aggregation of zone substation summer maximum demands, taking into account cross border flows, diversity and sub-transmission losses. These are then passed to AEMO for collation with other distributors' data, taking into account diversity. AEMO then publishes the total connection asset load forecasts in September.

UE's detailed procedure for undertaking the bottom-up load forecasting for Transmission Connection Assets is provided in the Maximum Demand Forecasting Method UE PR 2200 located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Procedures/UE%20PR%202200%20Maximum%20Demand%20Forecasting%20Method>

Although NIEIR does develop connection asset maximum demand forecasts for UE based on a top-down approach, the NIEIR connection asset forecasts are only used by UE as a guide to verify the internally developed bottom-up connection asset forecasts. The bottom-up connection asset forecasts scaled to match the NIEIR total UE service area forecast is what is officially used by UE as the connection asset forecast.

Transmission connection asset forecasts cover a 10-year planning horizon and are developed for summer and winter maximum demand at 10% and 50% probability of exceedance.

### 10.1.6 Sub-transmission

Sub-transmission forecasts are developed after the zone substation forecasts are completed. They comprise of the bottom-up aggregation of zone substation summer maximum demands, taking into account cross border flows, diversity and sub-transmission losses.

UE's detailed procedure for undertaking the bottom-up load forecasting for Sub-transmission Assets is provided in the Maximum Demand Forecasting Method [UE PR 2200](#) located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Procedures/UE%20PR%202200%20Maximum%20Demand%20Forecasting%20Method>

The sub-transmission forecasts are located in the same location as the zone substation forecasts in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/MaximumDemandForecasts/ZSS%20Feeder%20and%20SubT%20Forecasts>

Sub-transmission forecasts cover a 10-year planning horizon and are developed for summer maximum demand at 10% probability of exceedance.

### 10.1.7 Zone Substation

Zone Substation forecasts are developed after summer is completed and form the basis on which all UE's bottom-up forecasts are developed. UE's detailed procedure for undertaking the bottom-up load forecasting for Zone Substation Assets is provided in the Maximum Demand Forecasting Method [UE PR 2200](#) located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Procedures/UE%20PR%202200%20Maximum%20Demand%20Forecasting%20Method>

In determining a zone substation maximum demand forecast it is required to:

- Collect summer zone substation demand data;
- Determine the actual MW maximum demand, corrected for system abnormalities;
- Weather correct the actual demand to 10% probability of exceedance;
- Subtract off planned load transfers away from the station;
- Determine the growth rate for the station based on the estimated local growth, historical trend and growth relative to NIEIR total UE service area growth recommendations.
- Multiply the adjusted weather correct maximum demand figure by the growth rate
- Add in proposed major developments to be connected prior to the following summer from details contained within the large load register.
- Determine any power factor correction applied off the station prior to the next summer;
- Adjust station ratings for augmentation projects if relevant.

The zone substation forecasts are located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/MaximumDemandForecasts/ZSS%20Feeder%20and%20SubT%20Forecasts>

Zone substation forecasts cover a 10-year planning horizon and are developed for summer maximum demand at 10% probability of exceedance.

### 10.1.8 Distribution Feeder

Distribution feeder forecasts are developed after the zone substation forecasts are completed. They take into account new loads detailed in the large load register.

The distribution feeder forecasts are located in the same location as the zone substation forecasts in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/MaximumDemandForecasts/ZSS%20Feeder%20and%20SubT%20Forecasts>

Distribution feeder forecasts only cover a five-year planning horizon and are developed for summer maximum demand at 10% probability of exceedance.

The procedure for determination of feeder forecasts involves the

- Collection of summer and winter feeder demand data
- Determining the actual Amp MD, corrected for system abnormalities
- Subtracting off planned load transfers away from the feeder
- Determine the growth rate for the feeder based on zone substation growth and historical trend
- Multiply the adjusted Amp maximum demand figure by the growth rate
- Add in proposed major developments to be connected prior to next summer
- Determine any power factor correction applied on the feeder prior to the next summer
- Adjust feeder ratings for augmentation projects if relevant and record the limiting section

The aggregated feeder growth rate at a zone substation must be adjusted to match the overall growth rate at that zone substation to achieve reconciliation.

### 10.1.9 Large Load Register

The Large Load Register is populated by the Principal Engineer Network Planning throughout the year when advised from project planners from Service Providers or from the Customer & Market Operations team of proposed new loads connecting to the network. This information is used as an input to the zone substation and distribution feeder load forecasting process. The register should include both load increases and load reductions. It is located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/MaximumDemandForecasts/ZSS%20Feeder%20and%20SubT%20Forecasts/Large%20Loads%20Register>

A similar register exists for local council development applications:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/MaximumDemandForecasts/ZSS%20Feeder%20and%20SubT%20Forecasts/Local%20Council%20Data>

## 10.2 CAPEX Forecasting

Capex forecasting is undertaken annually as part of the asset management planning activities in the second half of the calendar year once maximum demand forecasts are finalised. There are two capex categories that UE's Network Planning team are responsible for forecasting, Demand Capex which covers all underlying load growth (generally deep-connection costs) and Customer Initiated Capex which covers customer specific load growth (generally shallow-connection costs). The capex forecasting period is 10-years based on finalised 10% probability of exceedance maximum demand forecasts, but also with a long term strategic capex forecast that has a 20-year projection using extrapolated maximum demand forecasts from the 10-year forecast based on three growth scenarios – business-as-usual, high demand growth and low demand growth.

Capex forecasting by the Network Planning team is undertaken in the following location and results in the preparation of the 20-year Demand Strategy and Plan document [UE PL 2200](#).

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Plans/UE%20PL%202200%20Demand%20Strategy%20and%20Plan>

A summary of this document is then included as a chapter in the overall Asset Management Plan (AMP), [UE PL 2000](#).

### 10.2.1 Demand Capital

Demand Capex (excluding DSS) forecasting is undertaken by the Principal Engineer Network Planning and includes forecasting of capex for all high voltage assets.

UE prepares a 10-year Capex works programme as part of the AMP each year for Demand Capex expenditure based on a 10% PoE summer maximum demand base economic growth forecast for the UE service area provided by NIEIR. This

forecast is distributed across each asset according to various localised growth conditions in the network for each of the network levels which form the power delivery chain from the transmission connection points to the customers' point of supply.

There is a two-staged approach for forecasting Demand Capex, a top-down and bottom-up method.

The top-down method seeks to calculate at a high-level the average annual Demand Capex requirements for the UE network based on the forecast average annual 10% PoE maximum demand growth in MW over the next 10 years. The entire power delivery chain from transmission connection point to customer connection point is affected by this increase in maximum demand. Therefore we must consider the Capex requirements at each of these network levels individually, with the total Capex requirement being the sum of all the components.

- **Sub-transmission** - The typical capacity provided by a newly installed sub-transmission loop is 128MW. UE's historical utilisation of sub-transmission lines has been approximately 50% of (N) on average, such that with one side of the loop out of service, the remaining side of the loop is able to carry 100% of the demand. With a certain MW of growth each year and two lines per loop, the number of new sub-transmission loops required each year would be  $MW \div 128 \div 50\% \div 2$ .
- **Zone Substations** - The typical cyclic capacity provided by a newly installed zone substation transformer is 40MW. UE's historical utilisation of zone substation transformers has been approximately 67% of (N) on average, that is, with one transformer out of service, the remaining two transformers at the zone substation are able to carry 100% of the demand. In situations where the zone substation is fully developed with three transformers, a new single transformer zone substation may need to be established with land purchase. With a certain MW of growth each year, the number of new zone substation transformers required each year would be  $MW \div 40 \div 67\%$ .
- **High Voltage Distribution Feeders** - The typical capacity provided by a newly installed high voltage feeder is 6.5MW for 11kV and 13MW for 22kV (the average being 9.75MW). UE's historical utilisation of high voltage feeders has been approximately 67% of (N) on average, that is, with one feeder out of service, the adjacent two feeders are able to carry 100% of the demand. With a certain MW of growth each year, the number of new feeders required each year would be  $MW \div 9.75 \div 67\%$ . Given that at least 2 new feeders are always established with a new zone substation transformer, the capex requirement is reduced for new feeders. Hence the total new feeders per year is likely to be less than that calculated.
- **Distribution Transformers and Low Voltage Circuits** - The typical capacity provided by a newly installed distribution transformer is 0.5MW. UE's historical utilisation of distribution transformers has been approximately 50% of (N) on average. With a certain MW of growth each year, the number of new distribution transformers and associated LV systems required each year would be  $MW \div 0.5 \div 50\%$ . Using the ADMD and the forecast customer number growth, it can be estimated what portion of the demand growth is attributed to existing customers and that of new customer connections. The portion associated with existing customers forms the basis for the DSS programme making up Demand Capex.
- **Reactive Power Compensation** - For a certain MW of demand growth each year, the increase in reactive power demand is likely to be 50% of the MW based on past experience. UE has pole top capacitor banks we use to address this growth in reactive demand each sized at 0.9MVAR. The number of new capacitor banks needed would be  $MW \times 50\% \div 0.9$ .

The average Demand Capex requirement is then calculated from the volumes identified above multiplied by typical project costs. The total annual Demand Capex requirement will be the sum of all network level components. An incremental cost of augmentation (\$/kVA) can then be calculated which can be compared with historical expenditure.

It is important to note that the above analysis is based on averages of growth over a 10 year period, and average utilisations. In reality, each network asset needs to be planned to support the localised demand within the relevant subsection of the UE service area for which it supports, and be operated within 100% of its utilisation capability. Using average utilisations for the whole network means that there are some assets in the population that are currently operating well above the average utilisation and some operating well below. Furthermore there are some assets experiencing higher than average demand growth and some that are experiencing lower than average demand growth. Therefore it is conceivable that augmentation requirements for those assets operating well above the average utilisation and in higher than average demand growth areas could be independent of changes in average maximum demand growth. Hence if the average maximum demand growth rate halves (for example) then it may take some time (likely to be more than 5 years) before the Demand Capex requirement also halves.

This method represents a simplified set of calculations to estimate the high level Demand Capex requirements to confirm the bottom-up detailed requirements which are highly technical in nature,

Demand Capex is forecasted bottom-up by taking the 10% probability of exceedance maximum demand forecasts for each network level and overlaying the summer rating information to calculate utilisation and identify the (emerging) constraints. For zone substation and sub-transmission assets, a projection of the value of EENS is also calculated (the same as that published in the DAPR) using a weighting of 10% PoE and 50% PoE forecasts.

The Demand capex forecasting process is always undertaken before a business case is developed and in most cases, many years before, particularly for the 20-year capex forecast. As such, engineering judgement is used based on experience to forecast the most likely suitable augmentation to alleviate a forecasted constraint and the likely timing for that augmentation. It is known that augmentations under a probabilistic planning approach can only be justified when the 10% probability of exceedance maximum demand exceeds the (N-1) cyclic rating, and that an augmentation is probably justified by the time the demand exceeds the (N) cyclic rating or the transfer capacity falling to zero. The likelihood of a project being economically justifiable is a function of the sensitivity of the demand to temperature and the cost of the proposed augmentation option. The higher either or both of these are, the higher the load needs to be above the (N-1) rating before an augmentation becomes economic. To facilitate the timing decision and to place less reliance on engineering judgement, the EENS (published in the DAPR) provides a good indication of the timing for a particular augmentation. When the value of the EENS exceeds the annualised value of the augmentation then the project is assumed to become economic.

Hence while the projects that build up the bottom-up Demand Capex forecast are based on estimated costs and estimated timings they are supported by:

- Estimates of costs provided by Service Delivery's internal estimators based on high level scopes developed by Network Planning included in the Capital and Operating Works Programme (COWP) and costs of similar like projects already completed;
- Estimates of timing supported by calculated published EENS values;
- Strategic Area Plans that may have been developed.

The detailed project needs analysis, cost and timing is then undertaken at the business case development stage. This occurs at the same time as the RIT-D for all demand capex projects over \$5m.

### 10.2.2 Customer Initiated Capital (CIC) & Distribution System Augmentation (DSS)

CIC Forecasting is undertaken by the Senior Engineer Network Planning.

The CIC forecasts are located in and involve the forecasting of unit rates and volumes to come up with capital expenditure forecasts.

<http://uenetwork.domain.prd.int/CustomerandConnections/CustomerCapitalForecasting>

The CIC forecast is strongly dependent on recent historical actuals (provided by the Service Provider planner spread-sheets and reconciled with the Finance team's records of historical actuals), varied by changes in customer number growth and construction industry growth indices. The CIC forecasting is undertaken by applying the methodology in the CIC Forecasting Guidelines document [UE GU 2202](#) located in:

<http://uenetwork.domain.prd.int/CustomerandConnections/CustomerCapitalForecasting/UE%20GU%202202%20Customer%20Initiated%20Capital%20CIC%20Forecasting%20Guidelines>

DSS Capex Forecasting is undertaken by the Senior Engineer Network Planning and includes capex forecasting of all distribution substation and low voltage assets.

The DSS capex forecasting is undertaken by applying the method in the Distribution System Augmentation Forecasting Guidelines document [UE GU 2203](#) located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Guides/UE%20GU%202203%20Distribution%20System%20Augmentation%20Forecasting%20Guidelines>

# 11. Planning Documents

## 11.1 Demand Strategy and Plan

The Demand Strategy and Plan UE PL 2200 is produced annually by the Senior Engineer Network Planning with input and review from all Network Planning Engineers. It presents the current state a 20-year view of the network development under three growth scenarios.

The Demand Strategy and Plan shall be developed to align with the Strategic Asset Management Plan UE PL 2034 and its scenarios.

The Demand Strategy and Plan contains long term planning information for all network levels on the following topics:

- Overview of the network utilisation and capacity planning process;
- Capital expenditure drivers and factors influencing demand growth investment;
- Summary of network utilisation from previous summers;
- Network development maps;
- Future load growth scenarios taking into account economic growth, temperature sensitive load (predominantly air-conditioning), distributed generation, electric vehicles, storage, and demand management;
- Forecasts of customer numbers, maximum demand, annual energy, load factor, power factor, network losses and asset utilisation (with and without proposed augmentations);
- Reinforcement/Demand Capex and Customer-Initiated Capital forecast requirements; and
- Detailed 20-year works programme.

The Demand Strategy and Plan UE PL 2200 is located in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Plans/UE%20PL%202200%20Demand%20Strategy%20and%20Plan>

The Demand Strategy and Plan is supported by the Distribution Annual Planning Report (DAPR) UE PL 2209 which contains the risk assessments to support the need and timing of the proposed projects.

## 11.2 Load Forecasts

The Load Forecasts are produced annually by the Principal Engineer Network Planning.

Accompanying the Demand Strategy and Plan are the summer load forecasts for zone substations, sub-transmission and feeders. Zone substations are forecast up to 10 years in advance and feeders up to 5 years. Long term forecasts up to 20 years are developed for the Demand Strategy and Plan by extrapolating the 10-year forecasts, and adjusting for three growth scenarios.

Forecasts are developed based on:

- Actual loadings from the SCADA system corrected for any system abnormalities and weather corrected to 10% PoE
- Historical trends in growth
- NIEIR growth forecasts
- Local development activities
- Load increases as advised from Customer & Market Services or the Service Provider
- Power factor correction



- Load transfers

These forecasts are maximum summer demand forecasts only. The Load Forecasts UE MA 2200 are located in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Manuals/UE%20MA%202203%20Load%20Forecast%20Manual>

## 11.3 Distribution Annual Planning Report (DAPR)

The DAPR is produced annually by the Senior Engineer Network Planning with input from the Principal Engineer Network Planning and other stakeholders across the business. It must be published on the UE internet site by the 31<sup>st</sup> December.

The detailed contents of the DAPR are prescribed in Schedule 5.8 of the NER but at a high level include

- Information about the network;
- Maximum demand forecasts;
- Reliability performance;
- Network constraints;
- List of RIT-D projects;
- List of asset replacement projects that are greater than \$2M;
- Results of joint planning activities;
- Asset management approach;
- List of demand management activities;
- List of metering and IT projects;
- Network maps.

over a five-year period.

A link to the Transmission Connection Planning Report will be provided in the DAPR.

The DAPR UE PL 2209 is located in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Plans/UE%20PL%202209%20Distribution%20Annual%20Planning%20Report%20DAPR>

## 11.4 Distribution zone substation information

A 10-year and annual zone substation report must be published annually on UE internet site by 31<sup>st</sup> December.

The distribution zone substation reports are located in the subdirectory of

<https://www.unitedenergy.com.au/industry/mdocuments-library/>

## 11.5 Demand Side Engagement Document & Register

Under the NER Distribution Planning and Expansion Framework, UE is required to develop and maintain a Demand Side Engagement Document every three years. The Demand Side Engagement Document & Register is a requirement under 5.13.1 of the NER.

The Demand Side Engagement Document UE PL 2202 is reviewed every three years by the Senior Engineer Network Planning. It must be published on the UE internet site. The Demand Side Engagement Document UE PL 2202 is located in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Plans/UE%20PL%202202%20Demand%20Side%20Engagement%20Document>

The detailed contents of the document are prescribed in Schedule 5.9 of the NER.

The Demand Side Engagement Register is a register containing a listing of all parties interested in receiving correspondence from UE in relation to the RIT-D, DAPR and non-network opportunities. It is updated whenever a party advises UE wishing to be registered or to have their details updated. The update is performed by the Senior Engineer Network Planning. The register is located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/DemandManagement/Demand%20Side%20Engagement/Demand%20Side%20Engagement%20Register.xlsx>

## 11.6 Transmission Connection Planning Report (TCPR)

The Transmission Connection Planning Report (TCPR) is a joint planning document developed by the Connection Asset Working Group (CAWG), a working group of Network Planning Engineers from each Victorian DNSP. This document is reviewed annually and published with the DAPR. The CAWG is attended by the Senior Engineer Network Planning.

The TCPR provides load forecasts for each terminal station and details of planned augmentation activities on the transmission connection assets that directly affect the long term reliability of supply for UE.

The TCPR is located in the sub-directory of:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Plans/UE%20PL%202209%20Distribution%20Annual%20Planning%20Report%20DAPR>

## 11.7 High Level Scopes of Work

High level scopes of work are developed by the Principal Engineer Network Planning for inclusion into the overall Capital and Operating Works Programme (COWP) developed as part of the asset management planning process. The high level scopes are used by Service Delivery to develop budget pricing for the AMP and COWP.

## 11.8 Detailed Scopes of Work

Detailed scopes of work are written by the Network Planning Engineer responsible for the asset class. They detail the work required to implement a project and should be of sufficient detail to allow members of the Capex Panel to bid a fixed price for the works. There are standard templates for detailed scopes of work and these are located in:

<http://uenetwork.domain.prd.int/PublishedDocuments/Templates/UE-TP-0210.1%20Large%20Project%20Scope%20of%20Works%20Template.dotx>

## 11.9 Business Cases & the Regulatory Test

Business cases are documents written by the Network Planning Engineer responsible for the asset class.

These documents are written to obtain formal financial approval for the commencement of a particular project. They must contain executive summaries, recommendations and discuss the need, options, economics and timing of the projects.

The economics and timing of the projects need to be calculated using the financial evaluation model.

Business cases need to be approved through the Delegated Financial Approval (DFA) process and as a minimum, require the signature of the author, a peer reviewer, the Manager Network Planning & Strategy and either the General Manager Electricity Network or the CEO.

The business cases should discuss alternative options and the consequences of the 'status quo' (or 'do nothing') option. Discussion of 'non network' options is mandatory.

Business Cases are located in the project folders, which can be accessed by searching for the project via:

<http://uenetwork.domain.prd.int/SitePages/Projects.aspx>



The business case templates and financial evaluation model are located in:

<http://uenetwork.domain.prd.int/PublishedDocuments/Templates/UE-TP-2910.1%20Business%20Case%20Full%20Form%20Template.docx> and

<http://uenetwork.domain.prd.int/PublishedDocuments/Templates/UE-TP-2910.6%20Capex%20Evaluation%20Template.xlsm>

Under the NER Distribution Planning and Expansion Framework, UE is required to undertake a Regulatory Investment Test for Distribution (RIT-D) for network augmentation where the highest value of the credible option exceeds \$5 million (direct costs). The RIT-D is a requirement under 5.17 of the NER

The purpose of the RIT-D is to rank various distribution investment options and identify the option (be it network, non-network or a combination) that maximise the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

The RIT-D should commence once the business case is known to be economic, but before the business case is approved. Once the RIT-D process confirms the preferred project, the business case can be finalised for approval through the DFA process of the preferred project.

The RIT-D facilitates a three-stage consultation process and involves the publication of the following reports:

1. Non Network Options Report
2. Draft Project Assessment Report
3. Final Project Assessment Report

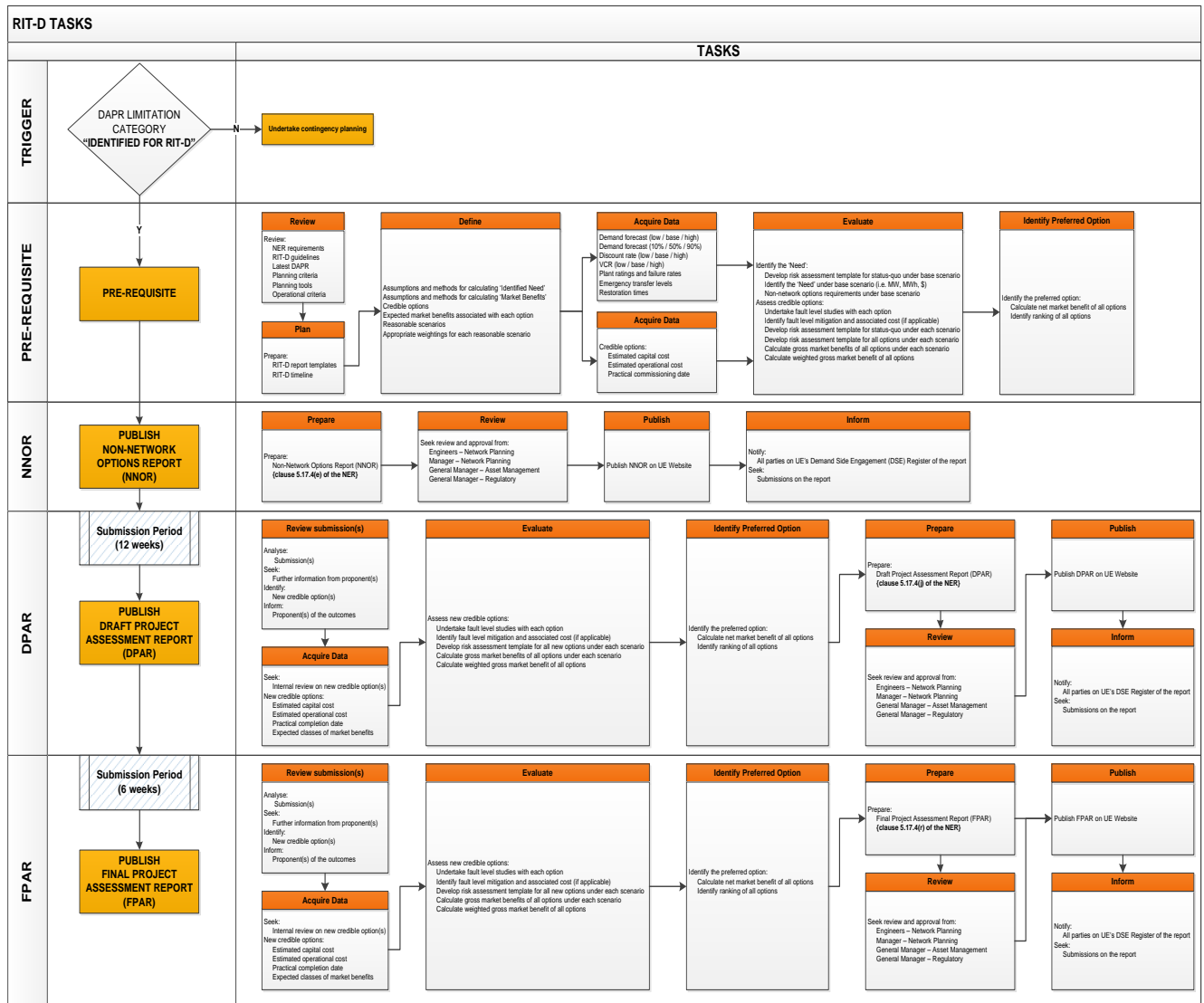
These reports provide the basis to consult industry participants, customers and registered parties on our Demand Side Engagement Register in identifying network investments that satisfy the RIT-D.

The RIT-D application guidelines are located in:

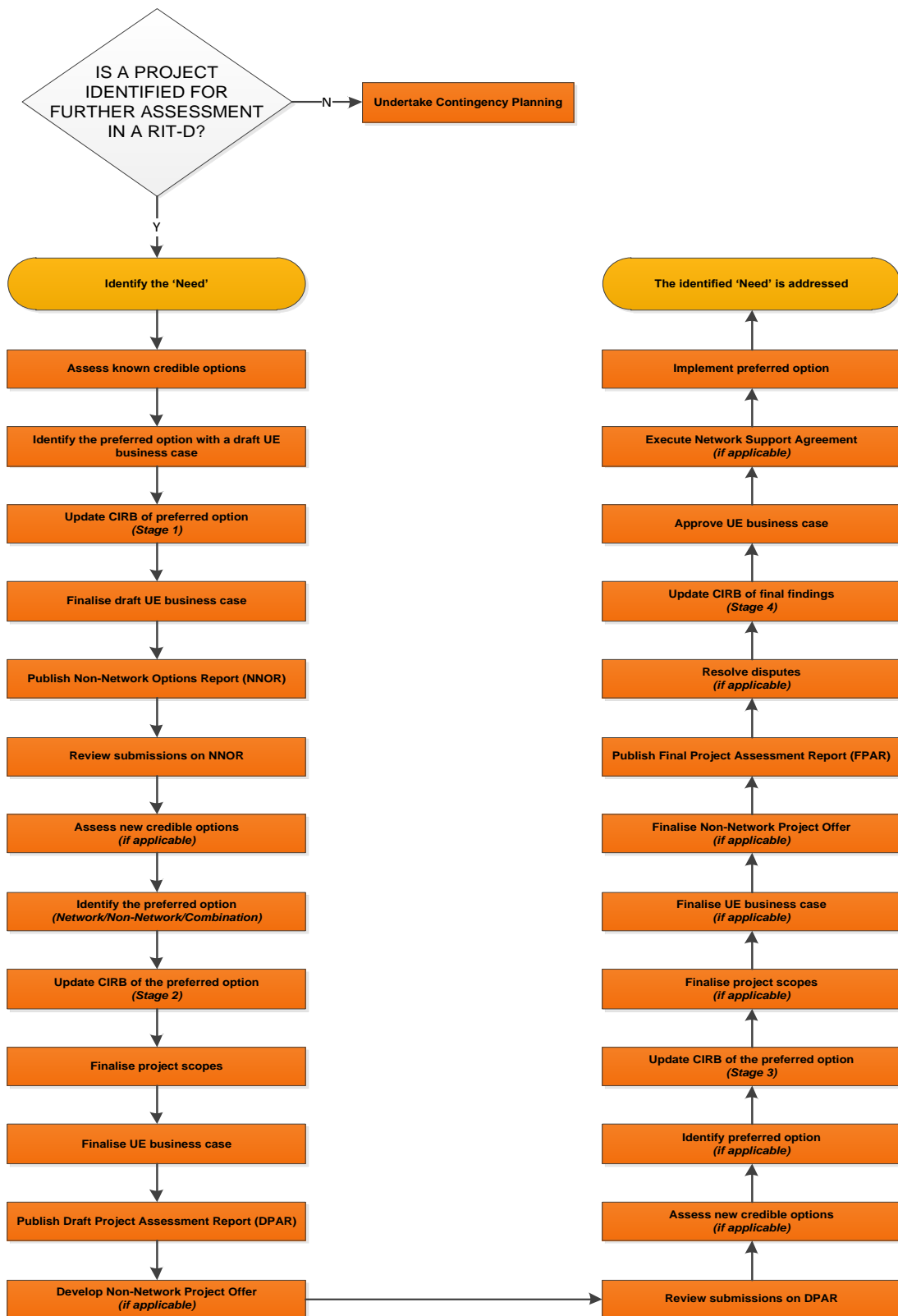
<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Reports/Regulatory%20Investment%20Test%20for%20Distribution%20RIT%20D/RIT-D%20Guidelines>

The RIT-D report templates are located in:

<http://uenetwork.domain.prd.int/PublishedDocuments/Templates/Forms/AllItems.aspx> The following process and workflow guidelines should be followed when undertaking a RIT-D assessment.



## UE RIT-D PROCESS GUIDE



## 11.10 Contingency Plans

Contingency planning is an important tool for network risk management. With the adoption of the probabilistic planning methodology, UE's network is exposed to single contingency events that can lead to loss of supply at times of high demand. To mitigate this risk, UE undertakes detailed contingency planning prior to seasons of high demand. The purpose of this planning is to reduce the impact of these events should they occur at time of peak (worst case scenario).

The contingency plans are produced annually by the Principal Engineer Network Planning with the distribution substation component of the plans provided by the Senior Engineer Network Planning.

These plans must be formally sent to NCC prior to summer each year and a meeting held to discuss the plans.

The contingency plans are targeted specifically at zone substations, sub-transmission systems and terminal stations. However the plans shall also include overloaded distribution substations and recommended sizes for emergency replacements should they fail.

While the contingency plans are focussed on the worst case single contingency, the plans should also consider a response to the impacts of credible common-mode failures that can result in multiple outages at the same time.

The contingency plans must be in point form detailing the steps that should be taken for the loss of equipment at a station or the loss of a line on a sub-transmission system for the forecast 10% PoE maximum demand of the upcoming summer. The steps are in the form of switching instructions. Summary tables present the risk before and after transfers.

The aim of these plans is to pre-plan credible single and common-mode contingency events to minimise the amount of time to restore load to customers and are essential in supporting UE's probabilistic planning approach. If it is not possible to restore all customer load then this is clearly highlighted in the summary tables of the contingency plans as a residual risk. Options to reduce voltage or relocate the relocatable transformer may be further mitigation measures to reduce the risk.

Contingency Plans are located in

<http://uenetwork.domain.prd.int/RiskAndEmergency/ContingencyPlans/UE%20MA%202204%20Contingency%20Plans>

The overall contingency plans for UE covers:

- Pre-contingency network optimisation prior to the high demand season to ensure plant items are loaded within their ratings under system normal;
- Remote selective load shedding and emergency load reduction capability from the 24-hour manned control centre;
- Assigning short term (24-hour, 2-hour and 10-minute) ratings for critically loaded zone substations and the use of dynamic ratings for critical plant items;
- A 12/20MVA 66/22kV relocatable transformer (currently located at CDA) and preparation of highly loaded zone substations to accept the relocatable transformer. This relocatable transformer enables rapid replacement of a failed transformer on the system within about 4 days;
- A 20/33MVA 66/11kV relocatable transformer (currently located at OAK) enables a failed transformer on the system to be replaced within about 4 days;
- Inter-station remote controlled switches on distribution feeders to enable fast load transfers (within 10 minutes) from the 24-hour manned control centre;
- Assessment of transfer capability away from the highly utilised zone substations and preparation of detailed switching instructions following a contingency;
- Communication plan for sensitive customers to keep them up to date with network issues on days of high demand;
- Demand-side resources;
- Operational measures including stepping up of field resource level and stock of spare equipment during summer peak period; and

- Contingency plans to cover transmission connection asset failure which include the use of distribution and sub-transmission ties.

Contingency plans are documented in [UE MA 2204](#) and updated annually.

## 11.11 Network Loading Report

The Network Loading Reports are produced by the Principal Engineer Network Planning (or delegate).

The Network Loading Report is a document released to the business via electronic mail after a hot day (typically 35 degrees or more) or unusual loading day.

The report summarises the loading on the DSS, HV and sub-transmission network, indicating clearly any abnormalities or overloading conditions and discussing any corrective measures (if any) to resolve the issues.

The data in the loading report is generated from standard reports from the OSI-PI and NLM historical databases.

Network Loading Reports are located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Reports/Network%20Loading%20Report%20NLR>

## 11.12 Strategic Area Plans

Strategic area plans are long-term detailed plans for addressing forecasted constraints in particular geographic areas, supported by network analysis studies. They may include the discussion of future augmentation options for high growth developing areas, or growth in existing built-up areas, fault level issues or long term planning standards for the business (such as retiring 6.6kV distribution for example).

The studies should be a broad strategy highlighting options for the area and include diagrams, charts and maps for ease of understanding. Load flow and fault level analyses should be included to confirm impacts of forecast constraints and technical robustness of options to address those constraints.

Strategic area plans are stored in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Plans>

Strategic area plans should be used as supporting material for business cases and the Regulatory Review submissions.

## 11.13 Controlled Documents

Controlled documents have a registered UE document number and required strict revision and review controls. They include policies, procedures, guidelines and strategies for the Network Planning team. The document numbers for the UE group are the 2200 series of documents. The current list of controlled documents owned by Network Planning includes:

- [UE PO 2200](#) Network Planning Policy
- [UE PO 2203](#) Power Quality Policy
- [UE PL 2200](#) Demand Strategy and Plan (input for the Asset Management Plan UE PL 2000)
- [UE PL 2201](#) Distribution System Augmentation (DSS) Strategy
- [UE PL 2202](#) Demand Side Engagement Document (Regulatory Deliverable)
- [UE PL 2203](#) Power Quality Strategy & Plan (input for the Asset Management Plan UE PL 2000)
- [UE PL 2204](#) Steady State Voltage Strategy
- [UE PL 2205](#) Distribution Substation Metering Strategy (to be developed)
- [UE PL 2206](#) Fault Level Management Strategy

- [UE PL 2207](#) Electric Vehicle Integration Strategy
- [UE PL 2208](#) Solar PV Penetration Strategy
- [UE PL 2209](#) Distribution Annual Planning Report (DAPR) (Regulatory Deliverable)
- [UE PL 2210](#) Demand Management & Demand Management Incentive Scheme (DMIS) Strategy
- [UE PL 2211](#) Land Acquisition Strategy
- [UE PL 2212](#) Value of Demand Management
- [UE PL 2213](#) Bus Tie Open Scheme Strategy
- [UE PL 2214](#) Summer Saver Program Strategy and Plan
- [UE PL 2220-2226](#) Strategic Area Plans (multiple documents supporting forecast capital expenditure)
- [UE GU 2200](#) Network Planning Guidelines
- [UE GU 2202](#) Customer Initiated Capital (CIC) Expenditure Forecasting Guidelines
- [UE GU 2203](#) Distribution System Augmentation (DSS) Expenditure Forecasting Guidelines
- [UE GU 2206](#) Network Planning Expenditure Forecasting Guideline
- [UE GU 2207](#) Network Losses - Application Guideline
- [UE GU 2208](#) Distribution Loss Factors (DLF) Calculation Guide
- [UE GU 2209](#) Electromagnetic Field (EMF) Guideline
- [UE GU 2210](#) LV Drop User Guide
- [UE GU 2661](#) Summer Saver Program Guideline
- [UE PR 2200](#) Maximum Demand Forecasting Method
- [UE PR 2201](#) NLM Data Provision Business Process Design
- [UE PR 2202](#) Network Modelling Procedure (to be developed)
- [UE PR 2203](#) Population of PQ Data for Annual RIN & ESC
- [UE PR 2204](#) Individual Harmonic Monitoring
- [UE PR 2205](#) Extracting ION Data for Long Term National Power Quality
- [UE PR 2207](#) After Diversity Maximum Demand (ADMD) Calculation Procedure
- [UE PR 2208](#) Preparation of DMIA Data for Annual RIN and DMIS Report
- [UE PR 2209](#) Population of Demand Data for Economic Benchmark (EB) RIN
- [UE PR 2210](#) Energy at Risk Assessment Tools Procedure
- [UE PR 2211](#) Population of Connections Data for Category Analysis (CA) RIN
- [UE PR 2212](#) Population of Augex Project Data for Category Analysis (CA) RIN
- [UE PR 2213](#) Population of Demand Data for Category Analysis (CA) RIN
- [UE PR 2214](#) Emergency Sub-transmission Tie Line Switching Instructions
- [UE PR 2215](#) Fault Locating Using PQ Information

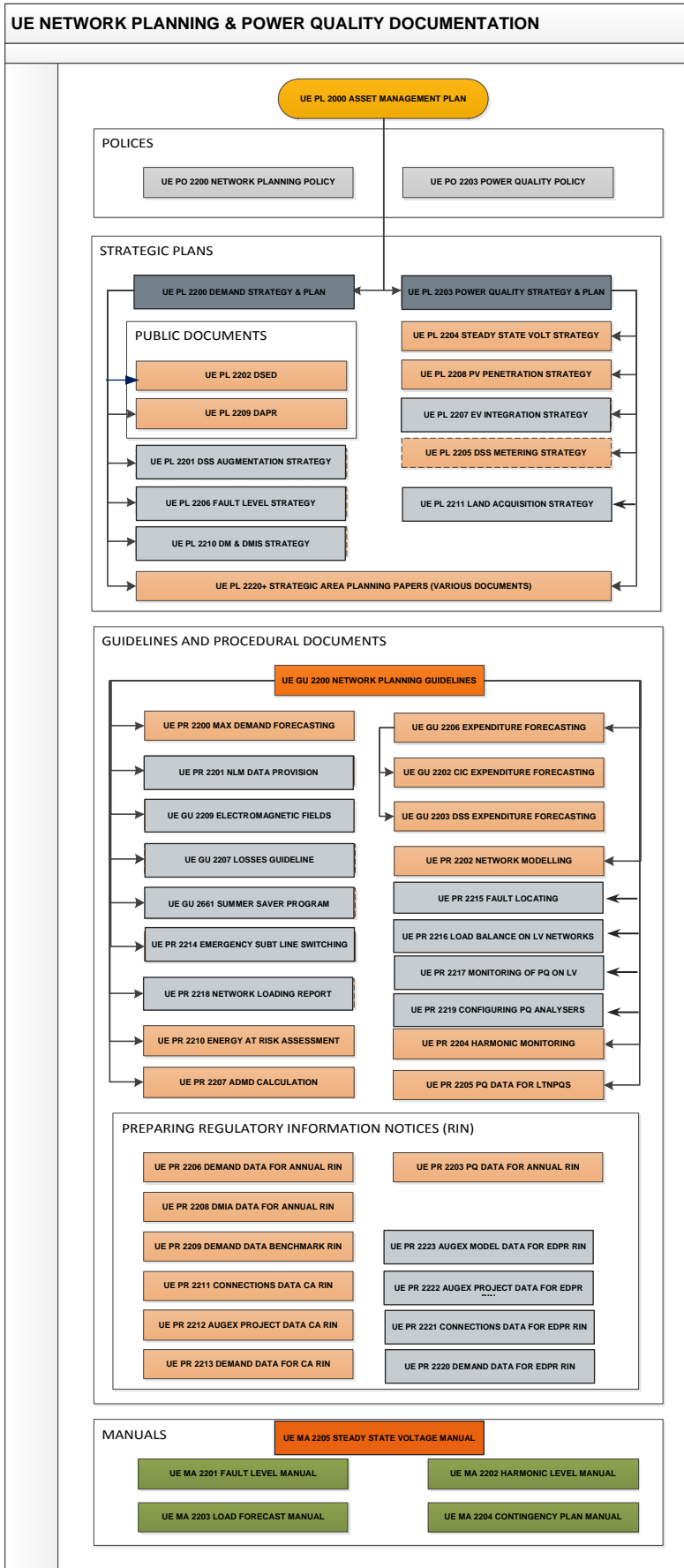
- [UE PR 2216](#) Load Balancing on Low Voltage Networks
- [UE PR 2217](#) Monitoring of Power Quality Disturbances on Low Voltage Networks
- [UE PR 2218](#) Preparation of a Network Loading Report (NLR)
- [UE PR 2219](#) Configurations for Power Quality Analysers
- [UE PR 2220](#) Population of Demand Data for EDPR (Reset) RIN
- [UE PR 2221](#) Population of Connections Data for EDPR (Reset) RIN
- [UE PR 2222](#) Population of Augex Project Data for EDPR (Reset) RIN
- [UE PR 2223](#) Population of Augex Model Data for EDPR (Reset) RIN
- [UE PR 2224](#) Installing CTs at End of Feeder PQ Meters
- [UE PR 2225](#) Summer Saver Event
- [UE PR 2226](#) Population of Augex Project Data for CA RIN
- [UE PR 2227](#) Population of Connections Data for CA RIN
- [UE PR 2228](#) Summer Saver Program Site Selection
- [UE MA 2201](#) Fault Level Manual
- [UE MA 2202](#) Harmonic Level Manual
- [UE MA 2203](#) Load Forecast Manual
- [UE MA 2204](#) Contingency Plans
- [UE MA 2205](#) Steady-State Voltage Level Manual
- [UE MA 2206](#) StruxureWave Power Monitoring Expert – User Manual

All controlled documents must have their published version placed in

<http://uenetwork.domain.prd.int/PublishedDocuments>

The register of controlled documents is located at:

<http://uenetwork.domain.prd.int/PublishedDocuments/DocumentRegister/UE%20ST%202110%20EN%20Document%20Register.xlsx>





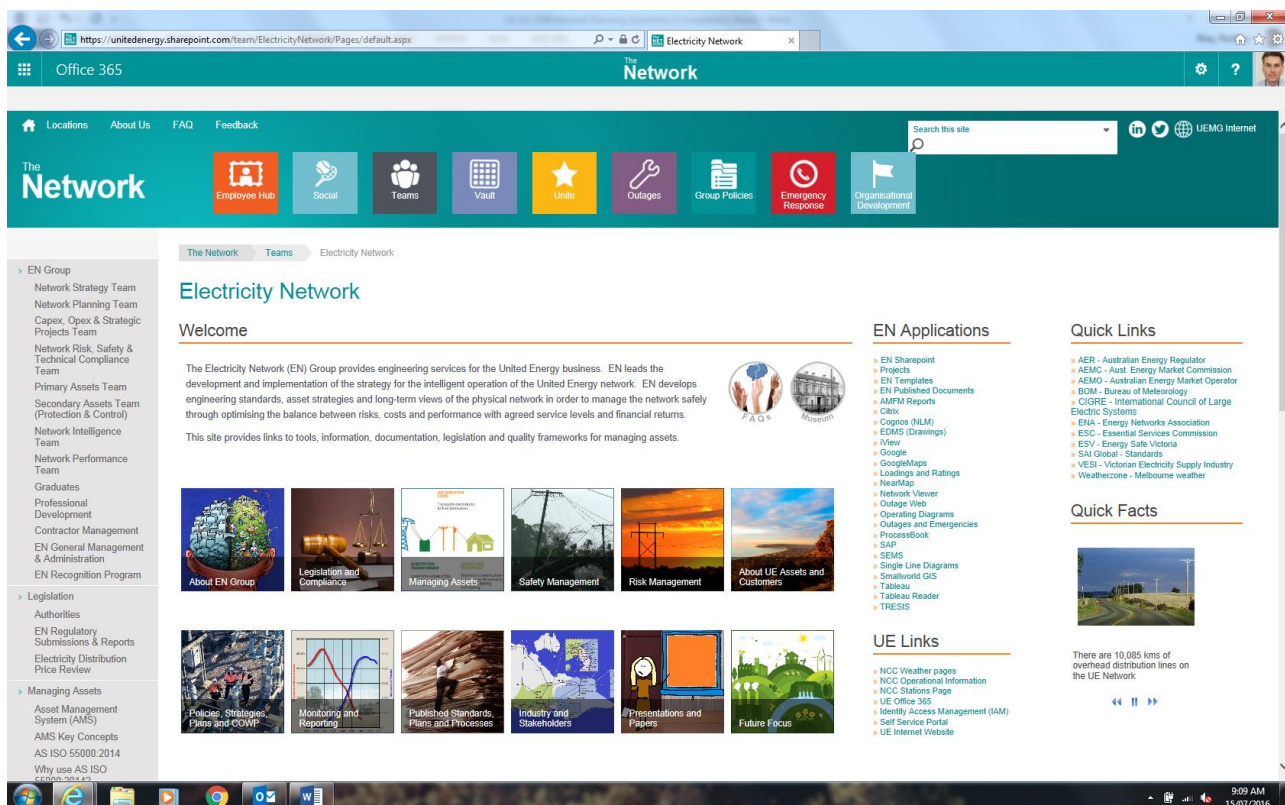
## 12. Planning Data Warehouses

There are a number of data warehouses used by Network Planning Engineers for their day to day activities. These data warehouses provide valuable metering, rating, network topology and asset information for assessing the network adequacy. They can be accessed from the [EN Intranet](#).

### 12.1 EN Intranet

The Electricity Network Intranet site provides access to a wealth of information, systems and external sites that Network Planning Engineers can utilise to perform their daily activities. The site can be accessed via

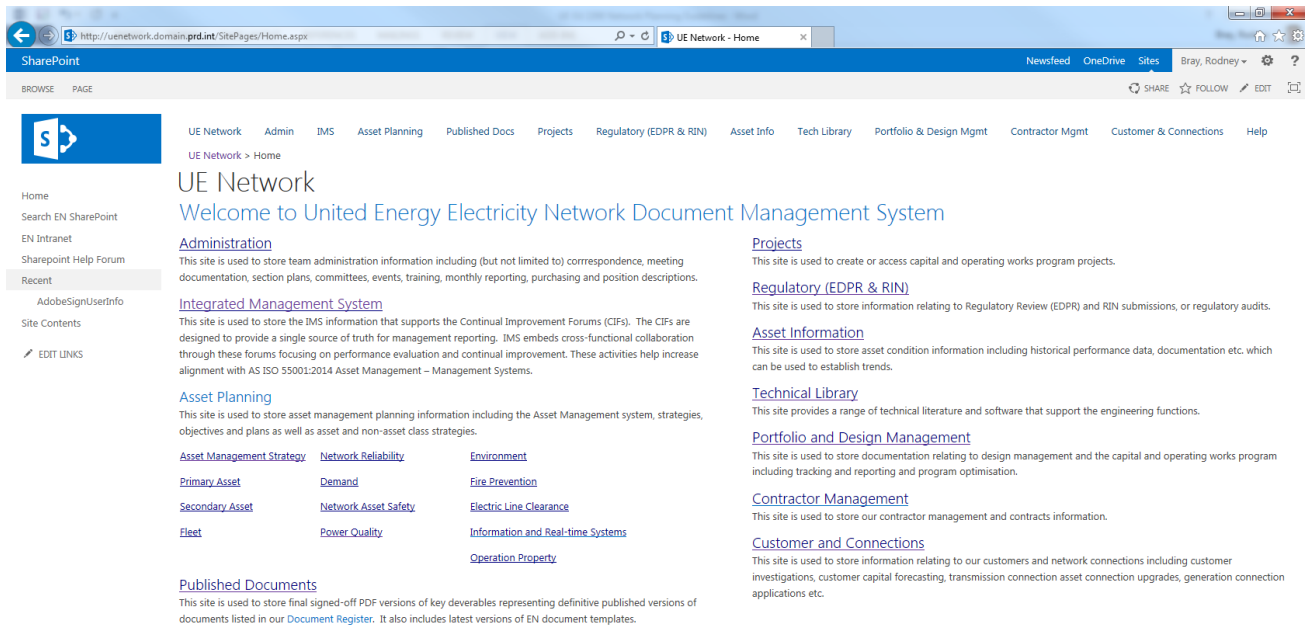
<https://unitedenergy.sharepoint.com/team/ElectricityNetwork>



### 12.2 EN SharePoint

The Electricity Network SharePoint site is a document management system that Network Planning Engineers should use to perform their daily activities. The site can be accessed via

<http://uenetwork.domain.prd.int>



## 12.3 OSI-PI

The OSI-PI data system is a suite of products aimed to allow easy access to the huge volumes of data generated by SCADA. Many parameters of network performance and behaviour are logged, this creates an enormous volume of information with challenges in how to categorise and organise it. OSI-PI is a system that aims to solve these challenges and also allow for quick and easy retrieval and usage of the data.

Predominately data is obtained from the PI data system using one of two tools – Process Book and MS-Excel Datalink.

### 12.3.1 Process Book

Process Book allows users to extract traces of system parameter behaviour. Any parameter stored in the system can be plotted alongside any other. This tool only has provision for creation, viewing and saving of traces, not so much for analysis.

This program is installed under the PI System folder within the start menu.

To obtain a trace using this tool follow the steps below:

- Launch PI ProcessBook
- Click 'File', 'New', 'OK'.
- Click on the Trend button



- Drag Select an area in the grey area window

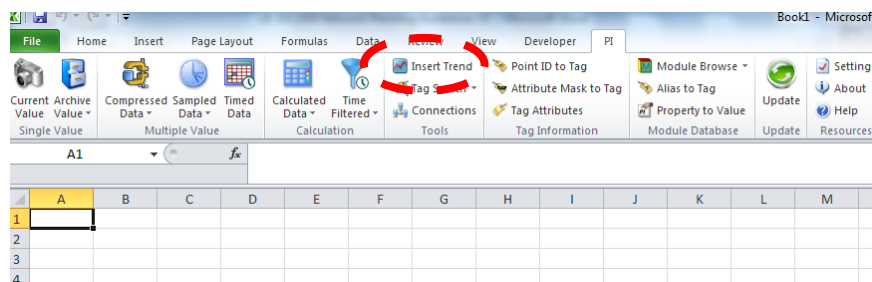
- Click “Tag Search”. Use wildcards to search for a network parameter to display and set the time period. Click “OK” and the trace should appear.

### 12.3.2 Datalink

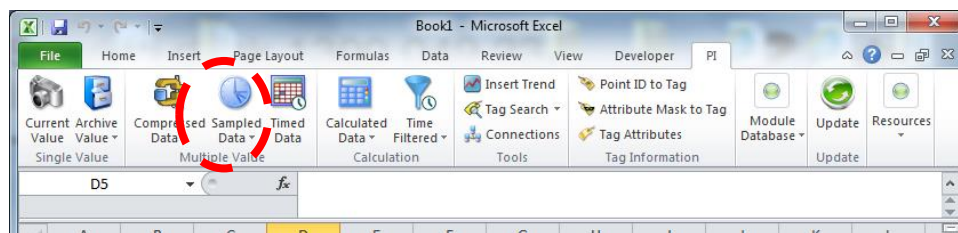
The great majority of PI data is accessed using the MS-Excel PI-Datalink plugin. This tool allows for data to be extracted to vectors (columns) in MS-Excel. Many different parameters can be extracted and placed alongside each other, easily synchronised time wise if required.

This allows for all the powerful analysis tools contained within MS-Excel to be brought to bear on the problem, not to mention the graphing facilities of MS-Excel.

Once installed the plugin should create a menu option in the ribbon in MS-Excel. Simply select the tab to access the PI functions. The trend functionality existing in Process Book also exists here.



To extract a regular time interval data series to MS-Excel from the PI data system, click on “Sampled Data”.



A pane will appear on the right, click the button next to Tagname to do a search for tags to extract from PI.

Populate the Tag name, Start Time, End Time and Time Interval (the first letter of the time unit is used for this field i.e. 1d for a day, 1h for an hour etc. It is possible to specify fractional times such as 0.5h)

Note that these input values can be stored in cells and references to these cells placed in these fields. This allows for automated (macro or otherwise) control of data extraction through PI.

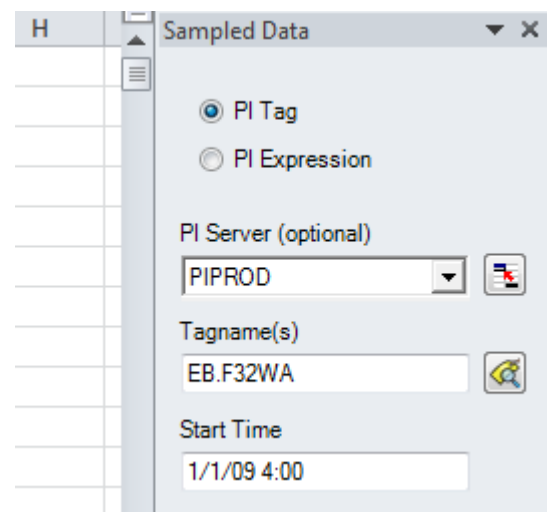
Check the ‘Show Timestamps’ tick box to get corresponding times of measurement displayed.

Choose an output cell (if ‘Show Timestamps’ is checked the resulting series will require 2 columns instead of one).

Click ‘OK’ and the series should appear in a column in MS-Excel (this can be changed to a row if desired)

OSI-PI datalink training information is located in

<http://uenetwork.domain.prd.int/TechnicalLibrary/SoftwareApplications/Demand%20Planning/OSI%20PI>



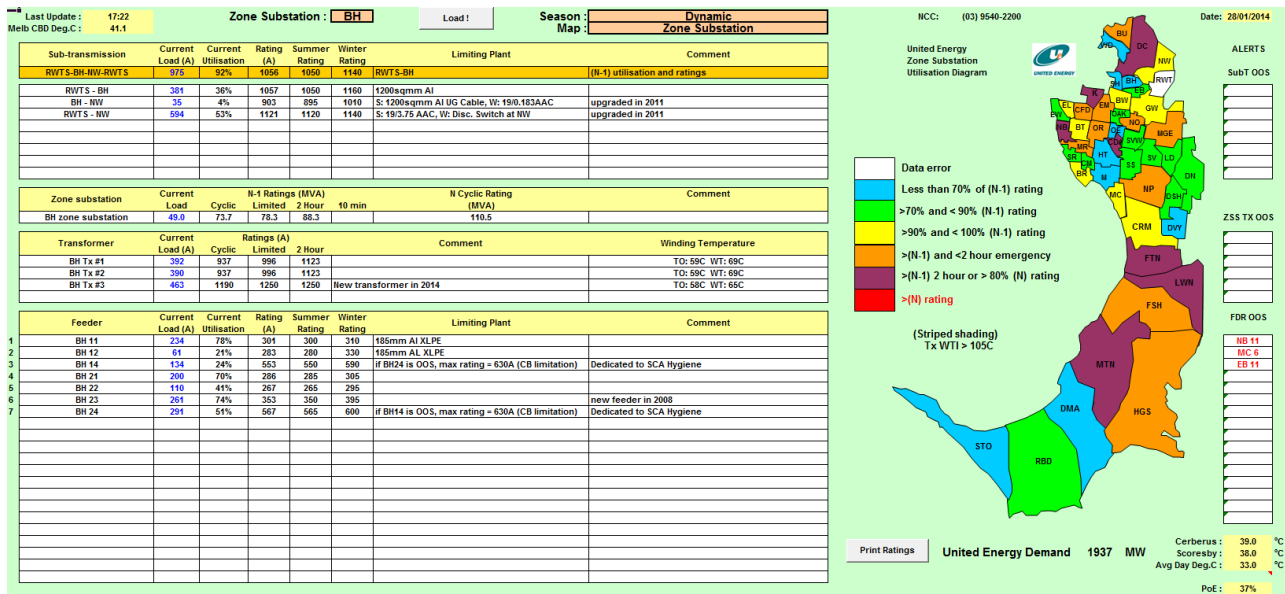
## 12.4 Loadings and Ratings Database

The Loadings and Ratings Database is managed and maintained by the Manager Network Planning.

The Loadings and Ratings Database provides a centralised, definitive, consistent source of ratings information for planning and operating the UE HV network. It is an important operational tool for the NCC in managing the day to day utilisation of the network. The master version of the “Loadings and Ratings Database” is located in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Ratings/NCC%20Ratings%20Database/Ratings.xlsm>

Changes to the database should be recorded on the “Changes” tab.



The database should be periodically issued to the NCC (at least quarterly) when updates have been made to the following address on the VAULT:

“Energy Delivery->Asset Planning & Strategy->Electricity->Ratings”

Once this is issued to NCC, the “Changes” tab in the definitive version should be cleared.

There are two sheets used commonly by the NCC – the ‘Zone Sub’ sheet and the ‘Network’ sheet. The remaining sheets hold the rating information entered by Network Planning.

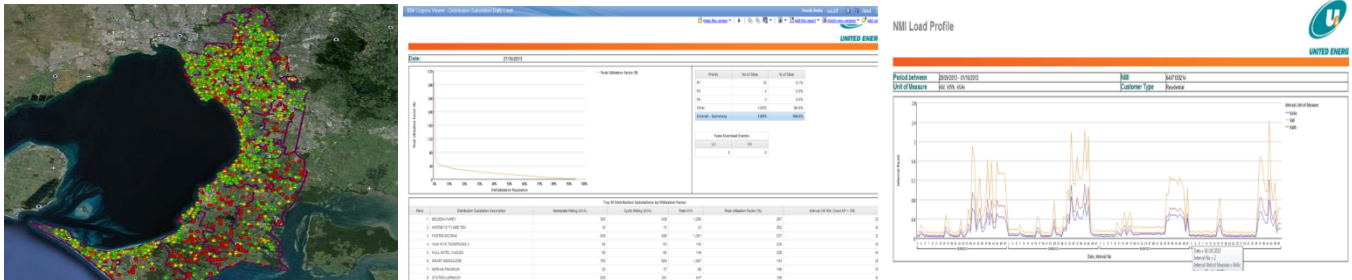
All rating information entered into this database by Network Planning should be sourced or calculated from ratings provided by the Primary Assets team and confirmed against protection min-ops provided by the Secondary Assets team.

The Loadings and Ratings Database requires PI-Datalink because it is a real-time tool to display present loadings and utilisations for the NCC and for summer load monitoring.

Given the Loadings and Ratings Database is the definitive source of rating information, all other Network Planning spreadsheets, records and models should source rating information from this database to ensure consistency.

## 12.5 Network Load Management (NLM)

The NLM data system is a suite of Cognos and Google Earth reports aimed to allow easy access to the huge volumes of data generated by interval metering data, in particular the AMI smart meters. The data in NLM is presented in aggregated form at each network level and is an important source of data for distribution substation and low voltage circuit loading. Snapshots of NLM reports are shown below.



The Google Earth reports are stored in:

[G:\Operations\WLM](#)

The GIS Upload report generated by NLM should be uploaded into GIS each year after summer to allow accurate power flow simulations to be undertaken in GIS.

The TLM report generated by NLM is used for developing the Distribution System Augmentation (DSS) works programme each year.

## 12.6 Smart Meter Data (AMI)

The Smart Meter Data (AMI) is provided to Network Planning through a web interface and data aggregation tool. It contains interval metering data for all NMIs less than 160MWh/annum.

The data can be visualised through Tableau or various web interfaces available through the EN Intranet.

## 12.7 AMFM-GIS (Network Viewer) & SAP

AMFM-GIS holds all of the geo-spatial information of UE's network. It is also used to undertake all power flow and fault level studies on the HV distribution feeders. Information on UE's assets resides in SAP but some of this information is ported across to the GIS. A web browser version of AMFM-GIS can be accessed through the Network Viewer application.

## 12.8 Drawings (Meridian - EDMS)

Detailed drawings including Circuit Data Sheets, detailed route plans and zone substation design drawings can all be accessed through the Meridian EDMS system.



## 13. Probabilistic Planning

Probabilistic planning has been adopted by UE and is undertaken by Network Planning Engineers as part of the UE business case economic evaluation process and as part of the RIT-D cost-benefit analysis.

Prior to 1997, UE's network planning had been based on a deterministic (N-1) planning criterion. The basic weakness of this approach is that while it provides 100% backup at all times it does not take into account the random (probabilistic) nature of system behaviour, customer demands, component failure, or transfer capacity.

The planning criterion of choice greatly influences the level of capital expenditure on a network. Deterministic planning criteria such as (N-1) planning will result in greater capital expenditure and higher network charges, but they may not necessarily result in a commensurate improvement in reliability and security. With the (N-1) planning criterion, the network must be designed to have sufficient capability such that for loss of any single element, the loading on all in-service elements remain within their design ratings at all times and for all time with no emergency action required. This no-risk approach is applied irrespective of the cost of the augmentation, albeit the augmentation is selected as the least cost technically acceptable solution.

UE's network loading is generally at its highest on hot days in summer. The plant ratings, on the other hand, are generally at their lowest in summer. With the present ratings and loading levels, most plant items in our network are expected to remain within their (N-1) ratings most of the time in a year, except on hot working weekdays in summer. When plant failure rates are taken into account, results generally indicate that for highly reliable plant, the probability of an element out of service at times of high load is small. Planning approaches that take into account the combination of load profiles, plant ratings and failure rates are called probabilistic planning. UE has adopted the probabilistic planning approach because it allows an economic assessment to be made on the cost of network augmentation compared with the cost of risk of loss of supply to customers. In other words, it provides a tool to achieve a balance between costs to customers and customers' loss of reliability costs, optimising the use of capex and delivering lower network charges to customers.

### 13.1 Markov Reliability Modelling

The use of probabilistic planning means adopting a reliability model to the economic evaluation of projects, quantifying the Expected Energy Not Supplied (EENS) and multiplying this by a Value of Customer Reliability (VCR) to quantify the cost of unreliability to customers. This can be directly compared against the annualised capital cost of the proposed project. The reliability model adopted by UE to achieve this is based on Markov modelling principles which use component failure rates and repair time data to determine the unavailability of parts of the system, overlaid with network load profiles and rating data.

In 1907, A. A. Markov (1856-1922), a Russian Mathematician introduced a special type of stochastic process whose future probabilistic behaviour is uniquely determined by its present state. It is obvious that this type of behaviour is non-hereditary or memoryless. With the introduction of Markovian property, problems are simplified considerably, since the knowledge of the present decouples the past from the future. A variety of physical systems fall into this category that has significant applications in reliability engineering. Markov reliability modelling is widely used in the electricity industry as a best practice to quantify the combined probability of plant outages.

Consider for example a two-transformer zone substation, fully switched but without sub-transmission line circuit breakers whose single line diagram is shown below.

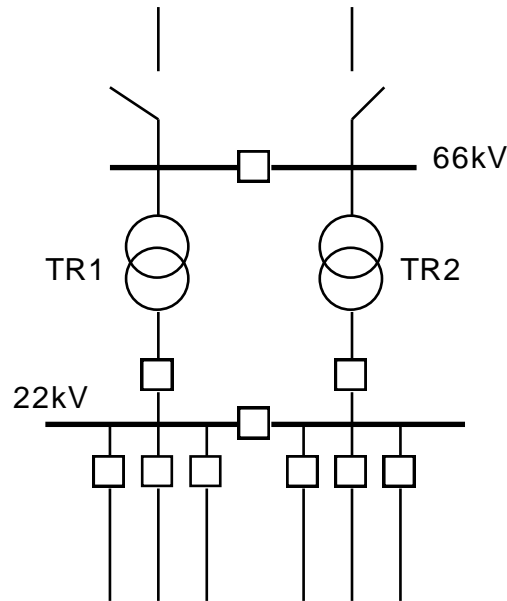


Fig. 1 Zone Substation Diagram

This zone substation has two sources of supply, therefore can be represented in a reliability block diagram with two limbs in parallel as shown below with the supply to any one feeder as a single limb.

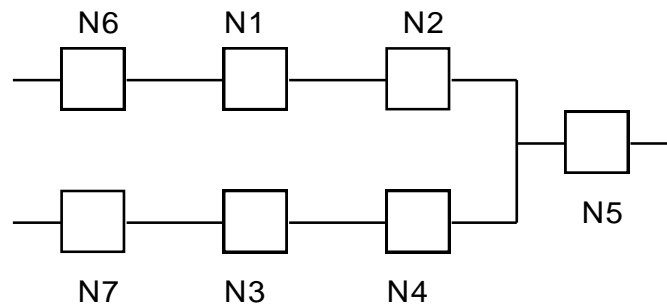


Fig. 2 Reliability Diagram

The reliability model for supply to any one distribution feeder is based on two 66kV lines supplying the substation, 2 66/22kV transformers and the 22kV feeder circuit breakers. This mirrors a common UE typical system arrangement, where transformers are considered as separate reliability elements as far as major failures are concerned (N2 and N4). The two 66kV lines are considered as two separate reliability elements (N6 and N7). Minor failures such as bushing failures and failures of auxiliary equipment were considered as another separate reliability elements (N1 and N3) in series with transformers (N2 and N4). Given 22kV feeders are radial, a failure will result in total loss of supply to the feeder, represented by reliability element N5. For simplicity, bus outages are not included in the above block diagram.

The overall system reliability is then assessed by considering the unavailability of individual element failures based on the failure rates, and repair times. When this is incorporated with the load profile and rating information, this can be used to calculate an Expected Energy Not Supplied (EENS). This is the value of the risk which could be avoided (in total or in part) by installing a third transformer. The annualised cost of deferral of the installation of the third transformer is calculated using the UE company discount ratio. Cost of this deferment is the cumulative value of the discounted risk values.

The optimum year to install the third transformer is when the EENS in any one year multiplied with the VCR exceeds the annualised capital cost of the project.

It is important that during this assessment, suitable sensitivity analysis is undertaken based on credible changes of the input variables and assumptions.

## 13.2 Value of Customer Reliability (VCR)

In order to determine the economically optimum level of augmentation, it is necessary to place a value on supply reliability from the customers' perspective. It is recognised that this value may depend on the customers involved (and the duration of the outage) and estimating such a value is inherently difficult. It is common practice by many utilities to use an average marginal value of reliability, referred to as the VCR. The VCR used by UE is based on a value derived from AEMO's 2014 VCR survey for the Victoria region. VCR is an important signal for investment and determining reliability levels. In establishing a case for an augmentation project, location specific VCR values are used to reflect the different classes of customers served by the augmented facility. To satisfy the requirements of a RIT-D, a set of scenarios is applied to test the sensitivity of the economic viability of a proposed augmentation against credible variations in VCR. It should be noted that the revised VCR values in 2014 were about 40% lower than the previous VCR value adopted by the industry. UE update the VCR on an annual basis revise the VCR to account for inflation in accordance with the AEMO guideline. The table below shows the changes in VCR from 2013 to 2014 and the current value of VCR adopted by UE (i.e. in 2018):

Table 1 – VCR estimates for Victoria (\$ per kWh) by customer sector

VCR (\$/kWh)	Summary of indexed VCR using OGW methodology and following AEMO 2014 VCR review				
Year	Agriculture	Commercial	Industrial	Residential	Victoria
2013	147.76	113.05	44.93	27.19	63.09
2014	47.67	44.72	44.06	24.76	39.50
2018	50.93	47.77	47.07	26.45	42.20

Capital projects that improve or maintain reliability also derive benefits from the STPIS regulatory incentive scheme whereby UE receives additional revenue based on supply reliability improvement but where the benefit stream diminishes once the reliability targets are reset. This represents a realised revenue benefit to the company rather than an assessed community benefit to the customers. At present UE assesses both the VCR benefit (used for RIT-D analysis) and the STPIS (used for business analysis) when developing demand-based project business cases in separate analysis areas of the standard economic evaluation model located in:

<http://uenetwork.domain.prd.int/PublishedDocuments/Templates>

There may be some situations where the results of the economic evaluation using the STPIS costs versus the VCR costs may be different. While the STPIS rates are derived from VCR, the difference may arise because STPIS is based on customer numbers and VCR is based on energy, hence for a highly industrialised area with high energy consumptions by relatively fewer customers, the difference can be quite marked. Under these situations, the differences need to be reconciled to ensure business investment decisions are aligned with the outcomes of the RIT-D. One way to achieve this reconciliation is to assume residential customers are shed prior to industrial customers in the event of capacity constraints as this is what would be implemented in practice.

VCR is used as part of the probabilistic planning approach to assess the economic benefits and costs to in making reinforcement investment decisions. An investment only proceeds if the net present benefits outweigh the net present costs, or when the benefit is regarded as a negative cost, the least cost option of the lifecycle of the asset. Applications of the VCR include:

- Transmission planning and RIT-T by AEMO and other TNSPs,
- Distribution planning and RIT-D by DNSPs,
- Calculating STPIS incentive rates for performance measures by the AER,
- Setting reliability standards by AEMC (for other states apart from Victoria).

VCR differs from the NEM "Market Caped Price" (previously referred to as Value of Lost Load – VoLL) which is based on the maximum ceiling price of the market spot price during the re-dispatch of generation to avoid shedding load shedding in



the event of insufficient generation. Rather, the VCR is determined through a customer survey approach that estimates direct end-user customer costs incurred from power interruptions at the sector and state levels.

The direct end-user customer cost of outage varies widely between consumer category depending on the activity of the consumer and to what extent that activity relies on electricity. The cost of outage can be easily quantified for some of the activities; while for some other can be less easy such as social disruption which is not captured by current methods.

The VCRs relating to a terminal station are calculated on an annual basis by the Connection Asset Working Group (CAWG) as part of the development of the Transmission Connection Planning Report (TCPR). UE may also calculates location specific VCRs when evaluating the timing of augmentation projects by considering the customers supplied by say a zone substation. These calculations are located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Plans/UE%20PL%202209%20Distribution%20Annual%20Planning%20Report%20DAPR>

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Reports/Regulatory Investment Test for Distribution RIT D>

### 13.3 Forced Outage Rates & Outage Durations

VCR is only one component in quantifying risk. It must be combined with plant unavailability based on forced outage rates and outage durations. The base reliability data adopted by UE is shown in the following table. The data is derived from the Australian CIGRE Transformer Reliability Survey carried out in 1995 and UE's network performance since 1994/95. A summary of the recent outage data that is used to update the failure rates and outage durations is available in:

<http://uenetwork.domain.prd.int/administration/CapexOpexTeam/UEMG%20Transformation%20%E2%80%93%20Electricity%20Network/Working%20Files/Initiative%2086/Outage%20Data%20Summary%20vs%20Planning%20Assumptions-Final.xlsx>

Major Plant Item:		Interpretation
<b>Zone Substation Transformer</b>		
<b>ZSS Transformer failure rate (major failure)</b>	1 in 200 transformers <sup>5</sup>  per annum	A major failure is expected to occur once per 200 transformer-years. Therefore, in a population of 200 zone substation transformers, for example, one major failure of any one transformer per year would be expected.
<b>Duration of outage (major failure)</b>	3 months	A total of 3 months is required to repair/replace the transformer, during which time the transformer is not available for service.
<b>Expected ZSS transformer unavailability per transformer-year</b>	(failure rate) x (proportion of year out of service) =  (1/200) x (3/12) =  0.125%	On average, each transformer would be expected to be unavailable due to major failure for 0.067% of the time, or approximately 11 hours in a year.

<sup>5</sup> During last 22 years (1997-2018) UE experienced 4 major transformer outages out of 111 transformer fleet.

Major Plant Item:		Interpretation
Sub transmission Lines		
Line failure rate (sustained fault)	4.8 per 100km per annum	The average sustained failure rate of UE Distribution's sub transmission lines is 4.8 faults per 100km per year. The failure rate used for each circuit has been varied depending upon its history.
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	$\begin{aligned} &(\text{failure rate} \times \text{length}) \\ &\times (\text{proportion of year} \\ &\text{out of service}) = \\ &(4.8 / 100 \times 10) \times \\ &(12/8766) = \\ &0.066\% \end{aligned}$	On average, a 10km 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.

The following outage rates and outage durations are used for UE's business case assessments.

Equipment	Outage Rate (pa)	Outage Duration
Zone Substation Transformer (major failure)	0.005	3 months
Zone Substation Transformer (minor failure)	0.10	18 hours
66kV Sub-transmission lines per km	0.048	12 hours
Transformer outage caused by sub-transmission line outage	n/a	1 hour
HV overhead lines per km	0.0625	6 hours
HV UG cables per km	0.01	29 hours
11 or 22kV bus (only used if credible contingency)	0.020	24 hours
11 or 22kV CB fail (only if credible contingency)	0.008	17 hours
66kV bus (only used if credible contingency)	0.005	24 hours
Load transfers (manual, multiple feeders or subT)	n/a	2 hours
Load transfers (manual, single feeder)	n/a	55 minutes
Load transfers (remote control)	n/a	10 minutes

AusNet Transmission Group have advised that the following parameters should be applied to transmission connection asset transformers.

Major Plant Item:		Interpretation
<b>Terminal Station Transformer</b>		
<b>Major outage rate for TS transformer</b>	1.0% per annum	A major outage is expected to occur once per 100 transformer-years. Therefore, in a population of 100 terminal station transformers, you would expect one major failure of any one transformer per year.
<b>Weighted average of major outage duration</b>	2.6 months	On average, 2.6 months is required to repair the transformer and return it to service, during which time, the transformer is not available for service.
<b>Expected TS transformer unavailability due to a major outage per transformer-year</b>	$0.01 \times 2.6/12 = 0.217\%$ approximately	On average, each transformer would be expected to be unavailable due to major outages for 0.217% of the time, or 19 hours in a year.

Note that in a detailed assessment process all site specific outage scenarios may also be taken into account. For example a 66kV line outage may also cause a transformer to be taken out of service. The base (average) outage data is also not applicable for replacement assessments which will take into account asset specific failure rate based on age and condition.

## 13.4 Multiples Failures

Generally only single failures, i.e. (N-1), are assumed to occur at any one time when quantifying risk for Network Planning purposes. However there are some instances where multiple failures, i.e. (N-2) or greater, must be considered in the planning process. The following scenarios shall trigger the consideration of multiple failures:-

1. When the failures are not mutually exclusive. These are referred to as common-mode failures where one cause can result in multiple outages simultaneously or within a short time period. Examples may include
  - a. An event impacting the structural integrity of a pole where multiple circuits may exist on the one pole such as vehicle-into-pole or pole fires.
  - b. An event impacting multiple circuits in a common geographic area such as bush-fires or control building fire.
2. When the failure rate or repair time is abnormally high. When a piece of plant is regularly tripping out of service or a very long repair time, the chances of a second failure occurring during that time is no longer negligible. Examples may include
  - a. A power transformer that is not backed up by a relocatable spare, where the replacement duration may last for several months.

## 13.5 Expected Energy Not Supplied

To calculate the expected energy not supplied (EENS) for single contingencies, the following formula is used in the business case evaluation that break the outage duration up into repair/replacement and load transfer time components.

$$EENS(MWh) = \frac{n \times F}{8766} \times \sum_{T=1}^{8766} \left\{ \sum_{t=T+L}^{T+R-1} \max(0, Load_{excess} - Load_{transfer}) + \sum_{t=T}^{T+L-1} (Load_{excess \ 2 \ hour}) \right\}$$

n = Number of parallel elements

F = Failure rate (number of outages per annum)

L = Load transfer time (hours)

R = min (Replacement time, Repair time) (hours)

T, t = Time in year (hours)

Load<sub>transfer</sub> = Transfer Capability (MW) at time 't'

Load<sub>excess</sub> = Load Above (N-1) Cyclic Rating (MW) at time 't'

Load<sub>excess 2 hour</sub> = Load Above (N-1) 2 hour Rating (MW) at time 't'

$$Risk \ Value \ (\$) = EENS \times VCR$$

EENS = Expected Energy Not Supplied (MWh)

VCR = Value of Customer Reliability (\$/MWh)

## 13.6 SAIDI

It is useful to determine the impact of risk on the customer minutes off supply. This reliability term is often called SAIDI (system average interruption duration index) and is equal to the average number of minutes off supply for every customer in the business. This is the measure upon which the STPIS is calculated.

$$SAIDI(minutes) = [U_{Repair \ or \ Replace} \times LF \times \max(0, Cust_{excess} - Cust_{transfer}) \times t_{excess} + U_{Transfer} \times LF \times Cust_{Excess \ 2 \ hour} \times t_{excess \ 2 \ hour}] \times 60 / Total \ Customers$$

U<sub>transfer</sub> = Unavailability during transfer (failure rate x load transfer duration in hours/8766)

U<sub>repair or replace</sub> = Unavailability during repair/replace (failure rate x (repair time-load transfer duration) in hours/8766)

LF = Load factor

Cust<sub>transfer</sub> = Transfer Capability (number of customers that can be transferred) at peak demand

Cust<sub>excess</sub> = No. Customers exposed above (N-1) Cyclic Rating at peak demand

Cust<sub>excess 2 hour</sub> = No. Customers exposed above (N-1) 2 hour Rating at peak demand

t<sub>excess</sub> = Time Load Over (N-1) Cyclic Rating per year (hours)

t<sub>excess 2 hour</sub> = Time Load Over (N-1) 2 hour Rating per year (hours)

Total Customers = Total number of customers in UE's service area

## 14. Economic Evaluation

Economic evaluation is undertaken by the Network Planning Engineer responsible for the asset class. An economic evaluation is required to ensure UE's capex investments are prudent.

### 14.1 Need

Every proposal to spend money must have a clearly stated, unambiguous objective. This objective is directed at solving some problem or issue that presently exists in the network. The proposal must also be consistent with the business' objectives.

### 14.2 Options

It is necessary to consider all possible options for a solution to the need and to weight their consideration to the benefits they provide. While not all options need to be evaluated in detail the two options that should be considered in greatest detail are the preferred option and the status quo (do nothing) option.

#### 14.2.1 Non-network solution requirements (demand reduction)

Non-network solution requests shall be initiated by the Principal Engineer at the time of evaluating all credible options to address a need. For network investment greater than \$6M, this shall be captured in the RIT-D process via the publication of the NNOR. This section relates investment that are less than \$5M, typically feeder augmentation projects:

When determining the suggested demand reduction requirements, allowance may need to be made for non-compliance or non-delivery of non-network solutions. It is proposed that 10% headroom is allocated at 11kV and 5% headroom is allocated at 22kV for non-delivery of non-network solutions. That is:

- Demand Reduction @ 11kV (kW) = 10% POE MD - (90% × Feeder Rating)
- Demand Reduction @ 22kV (kW) = 10% POE MD - (95% × Feeder Rating)

This will counter the risk of operating feeders at their capacity and uncertainties associated with the feeder demand forecasts too.

### 14.3 Probability Weighted Risk

The magnitude of expected network limitations, thus the energy at risk and STPIS cost, vary depending on 1 in 10 year (10% PoE) or 1 in 2 year (50% PoE) demand forecasts used for the assessment. Therefore, a probability weighted risk is used in the economic assessment of the project for the business case justification. In line with the RIT-T and RIT-D assessments, 30% of 10% PoE risk and 70% of 50% PoE risk are used to quantify the overall risk of a constraint.

### 14.4 Least Lifecycle Cost

Projects should be selected to maximise the overall net benefit to customers and the business by selecting the option which provides the present value least lifecycle cost, taking into account capex costs, opex costs and risks. Options should also be acceptable from a technical, environmental, social and safety perspective that satisfy all applicable rules, regulations and standards.

A standard economic evaluation tool is used by UE to select the option with the least present value lifecycle cost. This template is located in

<http://uenetwork.domain.prd.int/PublishedDocuments/Templates>

The majority of project options will be weighted economic decisions, and less costly deferrals may be necessary to reduce expenditure during tight fiscal periods. Deferral options are economic short term projects that can delay the installation of a more costly project by at least a year.

#### Economic Deferral Options

• Assigning short time (2-hour and 10-min) emergency ratings for critically loaded zone substations
• Re-rating the lines at higher operating temperatures
• Adopting dynamic ratings for lines according to wind speed and direction, and ambient temperature
• Capacitor banks for power factor correction have the added benefit of reducing the net load
• CBs on incoming sub-transmission lines at zone substations with full transformer switching
• Automatic emergency load shedding systems
• Network support (e.g. embedded generation, demand side management)

Projects should be ranked in priority according to their present value lifecycle cost. The project with the lowest present value lifecycle cost becomes the preferred project.

Some costs are qualitative rather than quantitative. While they are not included in the economic evaluation, reference to these should be discussed in detail in the business case and may be the deciding factor in deciding between two options with similar lifecycle costs. Such qualitative factors may include environmental considerations, societal impact, resource availability, or safety considerations.

The default period of time that the economic evaluation tool uses is 20 years. This is suitable for large capex projects which address a constraint for a significant period of time. For smaller projects, a shorter evaluation period is more prudent. The recommendations for suitable time periods are suggested below:

Asset Class	Assessment Time Period
• <b>New or upgraded terminal stations</b>	• 20 years
• <b>New sub-transmission</b>	• 20 years
• <b>New or upgraded zone substations</b>	• 20 years
• <b>New feeders</b>	• 6 years
• <b>All other capacity upgrades</b>	• 6 years

The economic evaluation tool uses a discounted cash flow model to calculate the present value of lifecycle costs. The discount ratio to use in the analysis is determined from the company Weighted Average Cost of Capital (WACC). The default discount ratio is set in the economic evaluation tool.

A discount factor is multiplied against the costs in each year of the evaluation to determine the present value of the cost, and these costs are summated to obtain the present value lifecycle cost. The discount factor is related to the discount ratio by the following equation:

$$\frac{1}{(1 + \text{discount ratio})^{N-1}}$$

where N is the year. The first year is N = 1.

The analysis does not include tax or depreciation.

The following diagram shows the input data page of the economic evaluation tool. The information is completed for each option being assessed.

## United Energy Business Case Template

Project Details		Negative Revenue Inputs / Sensitivities		Regulatory Investment Tests - Distribution (RII-D)		F-Factor	
Project Name	DVY12 new 22kV feeder	STPIS - Reference Case	Sustained - STPIS Period 1 to 2-3-4	Does the project contain augmentation component?	Yes	HBRA or LBRA	LBRA
Project Starting Year	2019	STPIS - Option 1	Sustained - STPIS Period 1 to 2-3-4	Is the augmentation component over \$5m?	No	Location Area	electric line construction
Project ID	UE-05A-13-001	STPIS - Option 2	Sustained - STPIS Period 1 to 2-3-4	Is this a reliability corrective action?	No	Fire danger period declared	Y
Project Type	Discretionary (augmentation and reinforcement)	STPIS - Option 3	Sustained - STPIS Period 1 to 2-3-4	<i>Notably Corrective Action: any augmentation must above \$5m required to meet the network service standards regulated under 52 for any other service standards required under the jurisdictional regulatory framework (the Victorian code)</i>		CFA fire danger rating	Severe
Regulatory Category	Demand (Reinforcement)	STPIS - Option 4	Sustained - STPIS Period 1 to 2-3-4	Regulatory Investment Test is not compulsory for this business case, but recommended.			
Budget Allocation (\$'000)	964	STPIS - Option 5	Sustained - STPIS Period 1 to 2-3-4				
Reference Case Description	Status Quo	Sensitivity Level	Level 2 - higher testing threshold				
Option 1 Description	DVY12 new 22kV feeder						
Option 2 Description	Power factor correction						
Option 3 Description	DVY24 and CRM21 feeder augmentation						
Option 4 Description	CRM15 new 22kV feeder						
Option 5 Description	Non-network alternative						

Capital Costs - All Scenarios		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reference Case	Status Quo	0																					
Option 1	DVY12 new 22kV feeder	1,076																					
Option 2	Power factor correction	225																					
Option 3	DVY24 and CRM21 feeder augmentation	1,373																					
Option 4	CRM15 new 22kV feeder	1,858																					
Option 5																							

Status Quo - Operating Costs (\$2019)		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Annual Maintenance Costs (\$'000)	1 yr post investment +3 (\$'000)																					
Negative Impact on Revenue (STPIS)																						
SAIFI sustained	(no. of interruption)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SAIDI sustained	(minutes)	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
MAIFI sustained	(no. of interruption)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage response	(percentage)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Network Outage Costs																						
Outage of supply	(minutes)	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Loss of F Factor Benefit																						
Loss of F Factor Benefit	(No. of fire start NOT avoided)																					
Costs																						
Reputational Costs and Media	(\$'000)																					

The following diagram shows the output data page of the economic evaluation tool.

## United Energy Business Case Template



### Project Details

Project Name	DVY12 new 22kV feeder
Year in which project will begin	2019
Discount Rate	6.37%
Project Type	Discretionary (augmentation and reinforcement)

### Regulatory Asset Category Proportion (Percentage)

Customer Initiated	0%
Demand (Reinforcement)	100%
Reliability & Power Quality Maintained	0%
Reliability & Power Quality Improved	0%
SCADA & Network Control	0%
Environmental, Safety & Legal	0%
Non-Network IT	0%
Non-Network general other	0%
Non-Standard Control	0%

### Economic Assessment

Is the project included in the Budget?	Yes
If yes, how much is allocated?	964

### Results

Least Cost Option	Option 1 - DVY12 new 22kV feeder
Least Cost (Present Value)	3,694

Options	Reference Case - Status Quo	Option 1 - DVY12 new 22kV feeder	Option 2 - Power factor correction	Option 3 - DVY24 and CRM21 feeder	Option 4 - CRM15 new 22kV feeder	Option 5 -
Capital Costs	0	1,100	240	1,410	1,899	0
Annual Maintenance Costs	0	0	0	0	0	0
Negative Impact on Revenue (STPIS)	4,959	2,988	4,750	4,375	3,631	0
Network Outage Costs	574	321	543	488	411	0
Loss of F Factor Benefit	0	0	0	0	0	0
Reputational Costs and Media	0	0	0	0	0	0
Cost 2	0	0	0	0	0	0
Cost 3	0	0	0	0	0	0
Cost 4	0	0	0	0	0	0

Two evaluations are performed – the business evaluation and the RIT-D evaluation. The RIT-D evaluation is only required for Demand Capex projects over \$5M in value (adjusted by AER from time to time).

## 14.5 Timing

The optimum timing calculated in the template is based on accrued risk and refers to the optimum commissioning time. Hence, the project lead time must be considered when determining the optimum time.

The load forecasts that are prepared are reasonably accurate for the initial five years if the load growth does not change drastically. This means that the timing of projects planned within this period is usually definite or will only vary by one year either side. For greater periods of time the timing of projects is more flexible and therefore requires reassessment each year. This flexibility allows the lumpy demand capex to be smoothed over time allowing better optimisation of available design and construction resources and budget predictability.

## 14.6 Business Case

The justification of a project needs to be prepared as a business case and approved by UE Management according to the company delegated financial authority. For projects over \$1.2M direct cost, endorsement is required by the Investment Committee prior to approval.

- The business case justification will need to include:
  - Background information
  - Discussion of why the project is needed – the ‘Need’
  - Growth forecasts
  - The potential impact of doing nothing
  - An assessment of all the options including non-network options – the ‘Options’
  - Costs and economic evaluation results of each option
  - Sensitivity studies to key input variables and assumptions
  - Optimum timing – the ‘Timing’
  - High level scope and cost breakdown of the project
  - List of assumptions made in the analysis

The templates to be used for business cases are located in:

<http://uenetwork.domain.prd.int/PublishedDocuments/Templates>

## 14.7 Project Costs

An assessment of the total cost of the options to be assessed in the economic evaluation tool must be performed in order to obtain an accurate result. The on-going maintenance costs and any other incremental costs over the life of the project will also need to be estimated and included in the model.

The costs consist of:

- Materials
- Labour (e.g. survey, project management, design, drafting, construction, testing commissioning)
- Overheads (Service Provider & UE)
- Ongoing operations and maintenance (O&M)
- Contingencies (Service Provider & UE)
- Land purchases<sup>6</sup> and easement acquisition

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<sup>6</sup> Land may have already been purchased but the purchase cost needs to be included in the business case.



Estimates of project costs shall be obtained from UE's Service Delivery internal estimators and this cost shall be used for the purposes of the business case. For large projects, the Service Provider may also be asked to do some preliminary surveys and costings to ensure that projects are accurately priced before issuing a request for Statement of Works. To enable the cost to be prepared, a detailed scope of works shall be developed by the Network Planning Engineer for the preferred option and high level scopes of works for the alternative options. Other teams within Asset Management may be required to assist in the development or review of the detailed scope of works.

The following annual O&M costs associated with HV underground and HV overhead should be considered in the business cases:

- Overhead: \$7.1k per km per annum
- Underground: \$2.6k per km per annum

These costs are in 2016 dollars and reflect all O&M activities based on actual costs including vegetation management, inspection, fault response and repair costs and any other maintenance activities. This is to replace the method of using a percentage of capital costs for estimating annual O&M costs. For all other solutions (including station works), O&M costs should be sourced from UE Asset Management.

A UE contingency amount should be included in the cost - generally a 10% contingency is sufficient, although this can be adjusted depending on the level of uncertainty.

## 14.8 Avoided Costs

Other costs to be included in the economic evaluation are those costs that can be avoided with the implementation of the preferred option. These costs are applied to the Status Quo and other alternative options and may consist of:

- Network losses costs
- Load at risk costs comprising of Overload Reliability, Switching Reliability and Constrained Plant
- STPIS (reliability incentive scheme) costs comprising of SAIDI, SAIFI, MAIFI
- Opex costs

Care must be taken to ensure that costs are not duplicated. For example, load at risk costs refer to the same costs as STPIS costs, just expressed in a different manner. The former refers to energy in MWh, the latter refers to customer minutes off supply based on the number of customers affected.

### 14.8.1 Network Losses

In every major network augmentation project, UE also evaluates the energy loss reduction that could be achieved from each feasible option, including network and non-network solutions. Network energy loss reduction benefits are quantified purely in terms of energy loss reduction and should be calculated using the method prescribed in the [UE GU 2207 Electrical Losses Guideline](#) document which is stored in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Guides/UE%20GU%202207%20Electrical%20Losses%20Guideline>

### 14.8.2 Overload Reliability

Reliability benefits are achieved because augmentation effectively increases the amount of redundancy in the network. Reliability benefits are calculated based on forced outage rates of equipment and VCR.

Overload Reliability effectively gives a measure of the transfer capability in the network. Highly loaded assets mean lower transfer capability which may result in less than 100% backup when a contingency occurs. The inability to transfer customers away from the problem when it happens is the source of Overload Reliability costs. Overload reliability can be applied to assets operating above (N-1).

#### Feeder Overload Reliability

$$EENS(MWh) = \frac{F}{8766} \times \sum_{T=1}^{8766} \left\{ \sum_{t=T+L}^{T+R-1} \max(0, Load - Load_{transfer}) \right\}$$

F = Failure rate (number of outages per annum)  
 L = Load transfer time (hours)  
 R = Repair time (hours)  
 T, t = Time in year (hours)  
 Load<sub>transfer</sub> = Transfer Capability (MW) at time 't'  
 Load = Load (MW) at time 't'

#### Sub Transmission Overload Reliability

$$EENS(MWh) = \frac{F}{8766} \times \sum_{T=1}^{8766} \left\{ \sum_{t=T+L}^{T+R-1} \max(0, Load_{excess} - Load_{transfer}) \right\}$$

F = Failure rate (number of outages per annum)  
 L = Load transfer time (hours)  
 R = Repair time (hours)  
 T, t = Time in year (hours)  
 Load<sub>transfer</sub> = Transfer Capability (MW) at time 't'  
 Load<sub>excess</sub> = Load Above (N-1) Rating (MW) at time 't'

#### Zone Substation Overload Reliability

$$EENS(MWh) = \frac{n \times F}{8766} \times \sum_{T=1}^{8766} \left\{ \sum_{t=T+L}^{T+R-1} \max(0, Load_{excess} - Load_{transfer}) \right\}$$

n = Number of parallel elements  
 F = Failure rate (number of outages per annum)  
 L = Load transfer time (hours)  
 R = min (Replacement time, Repair time) (hours)  
 T, t = Time in year (hours)  
 Load<sub>transfer</sub> = Transfer Capability (MW) at time 't'  
 Load<sub>excess</sub> = Load Above (N-1) Cyclic Rating (MW) at time 't'

### 14.8.3 Switching Reliability

Regardless of how much transfer capability there is in a network, there will always be some time delay in restoring customer supply after a load shedding contingency. Although augmentation will not affect this delay time, the number of customers and amount of load affected will change. For distribution feeders, Switching Reliability makes up the majority of SAIDI with the balance from Overload Reliability due to lack of transfer capability.

Switching Reliability can be applied to radial assets such as distribution feeders or single transformer zone substation, or assets operating over (N-1).

#### Feeder Switching Reliability

$$EENS(MWh) = \frac{F}{8766} \times \sum_{T=1}^{8766} \left\{ \sum_{t=T}^{T+L-1} (Load) \right\}$$

F = Failure rate (number of outages per annum)

L = Load transfer time (hours)

T, t = Time in year (hours)

Load = Load (MW) at time 't'

#### Sub Transmission Switching Reliability

$$EENS(MWh) = \frac{F}{8766} \times \sum_{T=1}^{8766} \left\{ \sum_{t=T}^{T+L-1} (Load_{excess}) \right\}$$

F = Failure rate (number of outages per annum)

L = Load transfer time (hours)

T, t = Time in year (hours)

Load<sub>excess</sub> = Load Above (N-1) Rating (MW) at time 't'

#### Zone Substation Switching Reliability

$$EENS(MWh) = \frac{n \times F}{8766} \times \sum_{T=1}^{8766} \left\{ \sum_{t=T}^{T+L-1} (Load_{excess\ 2\ hour}) \right\}$$

n = Number of parallel elements

F = Failure rate (number of outages per annum)

L = Load transfer time (hours)

T, t = Time in year (hours)

Load<sub>excess 2 hour</sub> = Load Above (N-1) 2 hour Rating (MW) at time 't'

### 14.8.4 Constrained Plant

Plant when loaded to its (N) ratings is no longer able to supply additional load. This is a loss of revenue to the business and can therefore be included as a cost. This cost increases over time if there is further growth in the region.

## Constrained Capacity

$$EENS(MWh) = \sum_{T=1}^{8766} (Load_{excess\ N})$$

T = Time in year (hours)

Load<sub>excess N</sub> = Load Above (N) Cyclic Rating (MW) at time 't'

## 14.9 Sensitivities

The aim of a sensitivity analysis is to determine the robustness of the economic analysis to variations in assumptions. Sensitivity testing must be undertaken based on various optimistic and pessimistic scenarios.

A separate sensitivity should be performed on every cost stream to determine which stream has the most impact on changes in the economics.

Where a project is border-line or uneconomic in the sensitivities, it shall be assigned a low ranking in the list of preferred options.

Concentration should be directed at the pessimistic scenarios. The scenarios should be realistic in that there is a reasonable possibility that the scenario can occur – that is they must be credible.

Some of the main sensitivity scenarios that need to be considered are cost, VCR, demand growth rate and discount rate.

## 15. Power System Simulation

The Network Planning Power System Models are managed and maintained by the Senior Engineer Network Planning.

A number of simulation packages are used by UE Network Planning Engineers. Instructions for operating these packages are contained in document, Network Modelling Procedure [UE PR 2202](#) located in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Procedures/UE%20PR%202202%20Network%20Modeling%20Procedure>

### 15.1 AM/FM - PSS/U

#### 15.1.1 Function

PSS/U is the standard computer program to perform studies on the high voltage distribution feeder network.

The program is used to determine:

- Feeder loadings
- Voltage profiles
- Fault levels

A power system simulation study should be performed on every feeder in the network on a two year rolling basis to identify and correct issues associated with:

- Inadequate voltage levels
- Overloaded conductors
- Reliability issues
- Losses

#### 15.1.2 Model

Network models are stored in AM/FM alternatives. The most up-to-date model is stored in the UE alternative in AM/FM however a PSS/U alternative should be created as a base case to allow user specific alternatives to be created below.

Users may need to make the following changes to these user specific alternatives in their studies:

- Changing substation loads
- Changing line and cable types
- Adding new network elements
- Changing source voltage set-points and impedances
- Changing switch status.

All substation load changes should be made in the 'Engineering Analysis Load' field of the substation editor. A value in this field will take precedence over the 'Maximum Demand' and 'Installed Capacity' fields. A change in this field will indicate to others that it is a substituted value.

Switch changes should be made to the 'Operating State' field in the isolating device editor. A click of the right hand mouse button when a switch is selected will enable the user to toggle a switch.

Changes to be kept in an alternative can be saved by committing the changes when the alternative is in writeable mode. To discard changes the alternative should be rolled-back.

### 15.1.3 System Studies

The PSS/U program shall be used for analysis of distribution feeder loadings and voltage profiles. Studies are performed either at peak or minimum load.

#### 15.1.3.1 CASE 1: Load Transfers – Current Check

Prior to switching of load from one feeder to another where there is a risk of overload, the following study shall be performed:

- Perform a load flow on the feeder that the load is to be transferred on to using the existing switching configuration entering no feeder demand
- Record the feeder current
- Calculate the diversity factor by dividing the feeder demand by the result in (2)
- Change the open point
- Perform a load flow on the feeder that the load is to be transferred on to using the new switching configuration entering no feeder demand
- Record the feeder current
- Calculate the difference and multiply by the diversity factor
- Perform a load flow on the same feeder using the new switching configuration entering the existing feeder demand plus the diversified transferred load in (7)
- Check no sections are overloaded

#### 15.1.3.2 CASE 2: Load Transfers – Voltage Check

Prior to switching of load from one feeder to another where there is a risk of a large voltage change, the following study shall be performed:

- Perform a load flow on each feeder using the existing switching configuration entering the feeder maximum demands
- Record the voltages on each side of the switch to be closed
- Calculate the percentage voltage difference
- If the difference is greater than 2% then the distribution substations should be surveyed and adjusted accordingly when the switching is performed
- Change the open point
- Perform a load flow on each feeder using the new switching configuration entering the feeder maximum demands adding or subtracting the transferred loads
- Compare the end of feeder voltages

#### 15.1.3.3 CASE 3: Identification of Conductor Upgrading

- Perform a load flow on the feeder entering the feeder maximum demand
- Display the current on the screen
- Those areas coloured as overloaded should be investigated for upgrade

## 15.2 PSS/Sincal

### 15.2.1 Function

This is the standard program to perform enhanced studies on the distribution network. The program is used to determine:

- Optimal Capacitor Placement
- Harmonic levels
- Tie point optimisation
- Feeder augmentation studies
- Integrated sub-transmission – distribution system studies

### 15.2.2 Model

Models can either be developed from scratch or imported from extracts created from the AM/FM – PSS/U system or from PSS/E.

## 15.3 PSS/E

### 15.3.1 Function

This is the standard program to perform studies on the transmission and sub-transmission network. Modelling the internal components of zone substation is also performed here. The program is used to determine:

- Sub-transmission loop loading and voltages
- Zone substation loading and voltages
- Fault levels (maximum and Minimum)
- Source impedances for the AM/FM – PSS/U system
- Contingency studies at the sub-transmission or terminal station level
- Dynamic simulations

### 15.3.2 Model

The sub-transmission model is not linked to AM/FM – GIS therefore any changes in the sub-transmission network must also be made in the PSS/E model. The PSS/E model include a single terminal station and all the zone substations attached to it. Zone Substations' loads and any other loads must be updated on an annual basis. The loads used in the base case models are coincident demands at time of terminal station maximum summer demand.

The data for the source impedance at the terminal station can be obtained from the transmission network PSS/E model provided by AEMO each year. This data is usually provided in the form of fault levels.

### 15.3.3 Transformer Modelling

Transformers are modelled typically on a 100MVA base, therefore impedances in Ohms or on nameplate rating should be converted to per-unit on 100MVA.

For transformers the negative sequence impedance is equal to the positive sequence impedance. For wye-wye-delta transformers (on 22kV system), the zero sequence resistance is approximately four times the positive sequence resistance. The zero sequence reactance is approximately 90% of the positive sequence reactance. For delta-wye transformers (on 11kV system), the zero sequence impedance is approximately equal to the positive sequence impedance.

Modelling of the NER is dependent upon the number of transformers that share one NER. The NER contributes an overall three times the NER resistance to the zero sequence resistance of the station where three transformers share the NER.



## 16. Non-Network Solutions

### 16.1 Embedded Generation

Embedded generation is generation that is paralleled and connected to UE's network.

The Principal Engineer Network Planning is responsible for assessing the Network Planning implications of proposed generation connections by working closely with the Complex Customer Connections Engineer and the UE Network Account Manager during the connection process.

#### 16.1.1 Access Standards

UE mandates access standards for the connection of embedded generation to the network and all generators connected to the distribution network in excess of 10kW (single-phase) or 30kW (three-phase) must have a signed Generator Connection Agreement. UE follows the connection process prescribed in Chapter 5 and 5a of the National Electricity Rules. UE's access standards for the connection of embedded generation are stored in:

<http://uenetwork.domain.prd.int/PublishedDocuments/Standards/UE%20ST%202008%20Embedded%20Generation%20Connection%20Standards>

There are specific Network Planning technical requirements that should be examined by the Principal Engineer Network Planning during the connection application process.

#### 16.1.2 Thermal Limits

The feeder backbone between the embedded generation site and the zone substation needs to be rated to carry the full output of the embedded generator less the minimum load of the distribution substations connected along the way.

In the absence of a Network Support Agreement, the feeder should be capable of carrying the full load with the embedded generation out of service. Alternatively, there should be enough transfer capability away from the feeder to account for the out of service contingency.

#### 16.1.3 Fault Levels

Connecting embedded generation to the distribution network may increase the short-circuit fault level on the network. The Principal Engineer Network Planning should check that this fault level is within the limits set by the Victorian Electricity Distribution Code and within the interruption capability of the switchgear and the conductors fault current carrying capability.

For inverter connected generation, the fault level contribution can be assumed to be limited to the normal power output of embedded generation.

#### 16.1.4 Reactive Control

The output of an embedded generator will affect the voltage on the distribution system.

For induction generators, the voltage will be lower with the magnetising current required to be supplied from the system for the generator. If the machine is started direct-on-line, the voltage variation should be checked with a motor start program or by hand calculation. A voltage dip of no more than 2.5% on the HV should be expected.

For synchronous machines with excitation control, the cogeneration scheme should be operating as close to unity power factor as possible or slightly lagging. The typical operating range for a generator is 0.85 power factor lagging to 0.9 leading.

For inverter connected generation, the inverter should be programmed for constant power factor (close to unity as possible), unless system studies warrant a different value being used.

#### 16.1.5 Quality of Supply

Connection of embedded generation to the network must meet quality of supply standards.

### 16.1.6 Minimum Demand

The size of the connected generation must be below the minimum demand of the protection zone so as to ensure the risk of islanding is minimised, otherwise an intertrip scheme may be required.

### 16.1.7 Referral to other Network Providers

In the event the generation exceeds 5MW, then the connection application should also be referred to AEMO for their consideration.

Where the embedded generator has an impact of increasing the fault level on another DNSP's network, then the connection application should also be referred to that DNSP.

## 16.2 Standby Generation

Standby generation is enacted by a customer by disconnecting their load from the grid and using their on-site generation to supply their entire load. This form of generation could be used to support the network in emergencies without the need for formal Generator Connection Agreements.

Standby generation must be reliable and able to be called upon in a short period of time. Its use is mainly to avoid initial load shedding in the event of a contingency for plant operating above (N-1). Standby generation will allow assets to be loaded to higher levels without increasing risk and therefore it is a suitable capital deferment option that should be considered.

## 16.3 Demand Side Management

Demand side management is achieved by having customers willing to shed load on demand or by prior arrangement when the spare capacity would generally be needed at times of high demand or during a critical plant outage.

For customers to participate in a demand management scheme, they need to have a good incentive. This can be achieved by paying or incentivising customers to be called upon at any time or for a predetermined time to shed their load. The magnitude of this payment in any one year must be sufficient to attract the customers by compensating them for lost production, but must not exceed the benefits to customers for avoiding the additional network capacity. Payment rates should be determined separately for each identified constraint to reflect the amount of risk UE is currently running with these assets and the potential capital deferments that can be achieved.

UE has an established residential demand side management programme called 'Summer Saver' which is used as an alternative to network augmentation solutions. The Summer Saver Guideline [UE GU 2661](#) is located in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/Guides/UE%20GU%202661%20Summer%20Saver%20Program%20Guideline>

UE also has standard network support agreements for large commercial and industrial customers, retailers and aggregators to provide demand side management services.

## 16.4 Voltage Reduction

Voltage reduction is an effective way of reducing demand in emergencies and UE has in place this capability with the ability to remotely control zone substation transformer tap positions. Voltages on the UE network are normally controlled through the action of the DVMS to V99% (according to AS 61000.3.100-2011). There is an options for NCC to select voltage reduction modes at V1% (preferred), or E1 or E2. The V1% modes undertakes a variable voltage reduction without taking customers outside of the regulatory limits, while E1 and E2 modes provide fixed voltage reductions.

It is well known that a small reduction in voltage results in a small reduction in load, albeit for a certain period of time, and can therefore be used as an effective form of emergency demand management. When determining the magnitude of the voltage reduction, the consequences of the voltage drop on the customers should be considered. In the past, the SECV commonly had emergency voltage reduction manually operated switches at zone substations providing a 5% voltage reduction. With the high utilisation of our networks today, this magnitude is considered too high at times of high demand. A value of no more than 3% would be better suited to the current network configuration. A decrease in voltage at the zone substation even by 3% may cause some parts of the LV network to fall outside the allowable range a specified in the

Electricity Distribution Code. Taps on distribution transformers are fixed and are generally set to provide nominal voltage for system normal conditions.

With DVMS now in service across the UE network, voltage excursions are being measured via AMI and compliancy with the Code is actively managed. Hence voltage reduction can be achieved by toggling operation from V99% to V1% without taking customers outside of Code limits.

The load behaviour to voltage varies depending on the mix of customer types. On distribution feeders, the load mix is not random. Certain feeders will have high components of industrial load and low domestic load, and vice versa. Below are approximate load indices.

Load Type	dP/dV (Change in P for 1.0% voltage change at 1pu)
Heating / Resistive	2.0 %
Synchronous Machines	0.0 %
Induction Machines / Fans	0.2 %
Lighting	1.6 %
Air conditioning	0.7 %

Customer Type	dP/dV (Change in P for 1.0% voltage change at 1pu)	
	Summer	Winter
Industrial	0.5 %	0.7 %
Commercial	0.8 %	1.4 %
Residential	0.9 %	1.5 %
Composite	0.7 %	1.2 %

## 16.5 Network Support Agreement

The Principal Engineer Network Planning is responsible for identifying non-network solutions and opportunities for entering into Network Support Agreements through the business case options process. The recommended method to be used to undertake joint planning with a third-party non-network provider is using a Memorandum of Understanding (MoU). An MoU template for joint planning to identify non-network solutions is located at

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/DemandManagement/Memorandum%20of%20Understanding>

The Senior Engineer Network Planning is responsible for identifying opportunities for entering into Network Support Agreements through the RIT-D process. The required method for identifying non-network opportunities under the RIT-D process is through the publication of the Non-Network Options Report.

Under the NER Distribution Planning and Expansion Framework, UE is able to engage non-network providers to defer distribution network augmentation. A Network Support Agreement has been developed to engage these providers contractually.

The location of the Network Support Agreement template is in

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/DemandManagement/Network%20Support%20Agreements>

Where an embedded generator may be able to alleviate an identified network constraint, then the generator proponent should be made aware of the network constraint and the opportunity to enter into a Network Support Agreement with UE to defer a planned augmentation.

Where a Generator Connection Agreement is applicable, this must be in place prior to entering into a Network Support Agreement.

The maximum service fee payable to the embedded generator shall be capped to the annualised financing cost of the preferred network option and scaled down commensurate with the reliability difference between the preferred network option and the embedded generation option.

Where the network augmentation being deferred is greater than the RIT-D threshold, then Network Support Agreements should be consistent with the conclusions of the RIT-D.

## 16.6 Reserve Capacity

The Principal Engineer Network Planning is responsible for formulating reserve capacity arrangements with the UE Network Account Manager.

Reserve capacity schemes are generally set up for customers to improve their reliability. The scheme involves setting up an automatic changeover switch so that when a fault occurs on the primary feeder, the customer is transferred to a backup feeder.

The advantage to the network planning process is that the customers pay for a DFA scheme if the transfer is set up between two feeders of different zone substations. The disadvantage is that open points become stranded at the customer premise and moving open points for load balancing becomes increasingly difficult.

Customers need to pay for the reserve capacity and this payment depends on the availability of the reserve and the amount of money the customer has contributed to the capital costs.

The reserve capacity offer model is located in:

<http://uenetwork.domain.prd.int/CustomerandConnections/MajorCustomerInformation/Reserve%20Capacity>

Generally reserve capacity contracts are established for a 5 year period. Surplus network capacity available for a reserve capacity scheme is calculated based on the forecast maximum 10%PoE demand at the end of reserve capacity contract period, and is fixed for the whole period.

Where there is already an auto-changeover switch and surplus capacity available in the reserve supply for the whole contract period (meaning that no augmentation is required), then the reserve capacity rate includes only the O&M costs associated with Radio Communication Fees, Administration Costs, Maintenance Costs, and Network Switching Costs. These costs should be reviewed by the Principal Engineer Network Planning on an annual basis in consultation with the UE Network Account Manager.

## 17. Interfaces

### 17.1 Service Provider & UE Service Delivery

#### 17.1.1 New Connections

The Service Provider Project Planners and the UE CIC Capex Managers should liaise with the Principal Engineer Network Planning (and vice versa) when there is a proposed load increase or new connection of 500kVA or greater. These proposals are to be incorporated into the load forecasts by way of the Large Load Register.

The Service Provider CIC Program Managers and the UE CIC Capex Managers should liaise with the Senior Engineer Network Planning (and vice versa) to facilitate CIC capex forecasting for the Asset Management Plan.

#### 17.1.2 Projects

The Service Provider DSS Program Managers and the UE Project Performance Engineers should liaise with the Senior Engineer Network Planning and LV Planning Analyst (and vice versa) for DSS demand capex projects.

The Service Provider Project Managers and the UE Large Capex Managers should liaise with the Principal Engineer Network Planning (and vice versa) for all other demand capex projects.

The Principal Engineer Network Planning and Senior Engineer Network Planning shall liaise with the UE Capex Project Estimators to obtain project costs for business case purposes.

The Manager Network Planning shall issue detailed Scopes of Work to Service Delivery developed by the Network Planning team.

The Manager Network Planning shall advise Service Delivery of approved Business Cases developed by the Senior Engineer Network Planning or the Principal Engineer Network Planning.

The Manager Network Planning shall provide updates to Service Delivery of the status of Business Cases and Scopes of Work being developed by the Network Planning team.

The Senior Engineer Network Planning is required to provide fault level information or system impedances on feeders, zone substation and terminal station buses to the Service Provider Project Managers to facilitate project delivery.

### 17.2 Network Control Centre

The Principal Engineer Network Planning is required to liaise with the NCC including:

- Planning advice to the NCC;
- Open point change requests;
- Handover of contingency plans;
- Issues regarding ratings or SCADA;
- Highlighting critically loaded feeders or substations; and
- Operational support.

The Manager Network Planning is required to provide the latest version of the Loadings and Ratings Database to the NCC.

### 17.3 Primary Assets

Primary Assets calculate and provide rating information for UE's Network Planning team. The Manager Network Planning shall update the Loadings and Ratings Database with the ratings advised by the Primary Assets team.

The Principal Engineer Network Planning shall work closely with the Primary Assets team to ensure that augmentation projects are aligned with replacement plans and vice-versa.

## 17.4 Network Intelligence

The Network Planning team shall work closely with the Network Intelligence team to identify inconsistency or errors in Network Planning data and shall work to develop information systems that facilitate the Network Planning functions.

## 17.5 Network Performance

The Principal Engineer Network Planning shall work closely with the Network Performance team to ensure that augmentation projects are aligned with performance projects and vice-versa, and ensure that the network configuration is optimised to maximise network performance.

## 17.6 Secondary Assets

A number of protection considerations needs to be taken into account when planning the distribution network.

### 17.6.1 Min-Ops

Distribution feeders (CBs and ACRs), zone substation transformers and buses, and some sub-transmission lines operate under an over-current protection scheme. Over-current schemes distinguish between load current and fault current using a 'min-op' such that currents greater than the 'min-op' will be seen as a fault and will trip the protective device.

'Min-ops' should be set by the Protection Engineers well above the rating and the peak load to prevent unintentional tripping of customer load. The Principal Engineer Network Planning should advise the Protection Engineers of the forecast peak demand through each protection device (including ACRs) as part of summer preparations prior to summer each year. The forecast peak demand should take into account both (N) and (N-1) switching configurations.

Changing of open points and feeder changes will need to be communicated to the Protection Engineers so that they are able to adjust protection settings if required.

'Min-ops' will also need to be recalculated by the Protection Engineers whenever feeder ratings are increased.

### 17.6.2 Fuses

Fuses are installed on the distribution system for protection of plant and equipment from excessive currents resulting from faults. They are not overload protection devices, hence it is required to keep peak load currents within the ratings of fuses.

In general, fuses are used for automatic feeder sectionalising following a fault, and substation transformer protection. If they operate due to overload, then action is required to either upgrade the fuse or relocate or remove the fuse. The Protection Engineers should be consulted to verify protection reach if changes to fuse sizes or locations are required to address overload issues. The Primary Assets team should also be consulted to verify capability of conductors to carry the expected fault current if changes to network fusing are required.

Care must be taken on fused spurs, fused LV circuits and HV fuses on distribution transformers when load is growing. The fuse size should be reviewed if there is any chance the fuse will blow under normal load. The fusing standard for UE is located in document UE ST 2009 – "Network Fusing Standard". This document specifies the maximum allowable fuse sizes for each application. For example, fused HV spurs shall have a maximum fuse size of 65A BA (for 22kV) or 125A PF (for 11kV), both of which can safely carry up to 2MVA of demand.

Fuses (EDO, PF or BA), as a switching device, are only capable of interrupting unloaded 22kV lines up to 16km in length or unloaded transformers up to 500kVA capacity, hence they are not recommended to be used in open point changes. In locations where the practicality of creating a no-load situation imposes unacceptable time delays in operating time a switch-fuse should be installed as the switching device for that spur. EDO fuses are only capable of interrupting fault currents of 2kA. BA fuses are only capable of interrupting fault currents of 10kA.

## 17.7 Customer & Market Operations

The Principal Engineer Network Planning shall liaise with the Network Account Manager (and vice versa) when there is a proposed load increase or new connection involving a major customer or a new generator connection. These proposals are to be incorporated into the load forecasts by way of the Large Load Register.

The Principal Engineer Network Planning shall liaise with the Network Account Manager (and vice versa) when there is a proposed change to Reserve Capacity arrangements.



## 18. Regulatory Deliverables

### 18.1 Distribution Loss Factors

UE must provide revised Distribution Loss Factors (DLFs) to the AER by the end of the first week of March each year to apply for the next financial year.

Clause 3.6.3(g) of the National Electricity Rules (NER) requires the DLFs to be calculated in accordance with a published method. The method must be either published by the Australian Energy Regulator (AER) or a method published by the Distribution Network Service Provider (where the AER has not published a method). UE has elected to use the Calculation Method for Distribution Loss Factors (DLFs) for the Victorian Jurisdiction (14 February 2007) published by the Essential Services Commission (ESC). This method is used for all of our DLF calculations.

DLFs are used to adjust customer's metered electricity consumption data to allow for energy losses in the electricity distribution network. The NER require that DLFs should be allocated to:

- each large customer consuming more than 40 GWh per annum or with a peak demand of 10MW or more – individual site specific DLFs are to be determined according to the customers' actual location on the network;
- each embedded generator of actual generation of more than 10MW – individual site-specific DLFs are to be determined according to the generator's actual location within the network;
- any embedded generator or customer who do not meet the above thresholds but requests a site specific DLF from the distribution business, provided they meet reasonable costs incurred by the distribution business, and
- all other customers and embedded generators. For this category of customer, generator network average DLFs are to be allocated according to the type of connection points within the distribution network.

The proposed DLFs must be independently certified that they have been prepared in accordance with the requirements of the AER. This has been traditionally done by Parsons Brinkerhoff (PB) which prepares a joint DNSP verification report.

The DLFs are calculated and stored in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/DistributionLossFactors>

The input data required for DLF calculations include total UE energy import at terminal station level for a previous complete financial year, total energy export by embedded generators for a previous complete financial year, total energy consumed by large customers (demand>10MW or energy >40GWh) for a previous complete financial year, maximum demand and total energy consumption of other larger customers that are not included in the previous list (typically demand >5MW or energy>25GWh), and total energy flows within individual metered sections of shared sub-transmission loops and dedicated feeders to/from other DNSPs for a previous complete financial year. The latter is also used for cross-border flow calculations.

### 18.2 Voltage Set-Points

UE must provide to AEMO by 15<sup>th</sup> May each year, the voltage set-points for each of its transmission connection points, agreed with other DNSPs sharing the terminal station. The voltage set-points are stored in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/ReactivePowerandVoltageRegulation/Voltage%20Regulation%20Settings/Terminal%20Station>

### 18.3 TSDF & UE Load Forecasts

UE must provide maximum demand forecasts to AEMO for the transmission points of connection by end of July each year. This is known as the Terminal Station Demand Forecast (TSDF) process.

These load forecasts shall be 10-year projections of point of connection active power and power factor for summer and winter.

A projection of the load curve for each terminal station should also be performed. This is generally based on historical curves obtained from the wholesale metering corrected for growth and system abnormalities.

The forecasts provided to AEMO are located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/MaximumDemandForecasts/Connection%20Asset%20Forecasts>

UE provides NIEIR with similar data for the UE boundary load and terminal station forecast each year. However the TNI aggregation sourced for load forecasts is different between NIEIR and AEMO.

For NIEIR, half-hourly MW and MVar data at individual TNI for a given period (typically one year from 1st of April to 31st of March) is required, and half-hourly MW and MVar data for embedded generators for the same period.

For AEMO, a template is provided to UE by AEMO for populating data for the TSDF. The data is based on half-hourly data, 10MD days, time and demand (MW and MVar both) for the last summer and winter seasons including weekends and public holidays at each bus group, TNI and terminal station (includes diversity among different NMIs in one terminal station). If numbers cannot be reconciled with AEMO, half hourly raw data will be required to drill down to find reasons for any difference. The MW and MVar values at individual bus group, TNI and terminal station for a given set of dates and times, the MW and MVar values of embedded generators for a given set of dates and times is required. Furthermore 15-minute MW and MVar data at individual TNI and 66kV bus groups (where applicable) on the maximum demand day for each year is required for a demand trace.

## 18.4 Annual Fault Level Review

UE must provide fault level contribution forecasts over 5 years period to AEMO at the transmission points of connection by end of June each year.

The forecasts provided to AEMO are located in:

<http://uenetwork.domain.prd.int/AssetPlanning/Demand/FaultLevelsandImpedances/Annual%20Fault%20Level%20Review%20AFLR>

## 18.5 Top 10 MDs

UE is required to provide to AEMO each year, the top 10 MD days for the purposes of Transmission Use of System (TUOS) rate calculations.

The data is based on half-hourly data, 10MD days, time and demand for the last summer excluding weekends and public holidays at each terminal station (not at TNI as some of the terminals stations have multiple TNIs).

The demand at individual terminal station (not at TNI level) for a given set of dates and times and total monthly energy from March of the previous year to February of the current year at each terminal station (not at TNI as some of the terminals stations have multiple TNIs) is required.

Demand on individual metered sections of shared sub-transmission loops and dedicated feeders to/from other DNSPs for a given set of dates and times is required.

If numbers cannot be reconciled with AEMO, half hourly raw data will be required to drill down to find reasons for any difference.

## 18.6 Regulatory Information Notices (RIN)

UE is required to provide data to the AER in the Regulatory Information Templates (RINs) after each calendar year. The procedures are detailed in the controlled documents with the data stored in

<http://uenetwork.domain.prd.int/AssetPlanning/EDPRandRIN/RINs>

## 19. Planning Activities and Responsibilities

Activities undertaken by the Network Planning & Strategy Team are documented in the annual section plan. The location of the Network Planning & Strategy section plan is:

<http://uenetwork.domain.prd.int/administration/NetworkPlanningTeam/Section%20Plan>

Staff and their responsibilities within the Network Planning & Strategy Team are documented on the Intranet:

<https://unitedenergy.sharepoint.com/team/ElectricityNetwork/EN%20Group/Pages/NetworkPlanningTeam.aspx>

## 20. Definitions

TERM	DEFINITION
ABC	Aerial Bundled Conductor is an insulated overhead conductor used in feeders where there are significant amounts of vegetation
ACR	Automatic Circuit Recloser. A pole mounted circuit breaker on a feeder that is programmed for a reclose operation for faults further down the feeder
ADMD	After diversity maximum demand
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AM/FM - GIS	The geographic information system of the UE network
Auto Close	A standby circuit breaker closing automatically after a trip of another breaker with the objective of transferring load to another item of plant
Auto Reclose	Circuit breaker closing automatically after a trip of the breaker
Bentonite	A material used to fill up cable ducts to improve the cable ratings
BIL	Basic Impulse Level. Used to describe the withstand capability of equipment to surges
CAIDI	Customer average interruption duration index = SAIDI / SAIFI
Capacitors	Power factor correction devices. They inject reactive power into the network
CB	Circuit breaker
Codes	Victorian System Code and Victorian Electricity Distribution Code
Connection Assets	The assets within a terminal station that are planned by UE.
Contingency	Failure of an item of plant. Normally in-service equipment forced out of service by an event
Critical Contingency	A single contingency that has the worst outcome.
DNSP	Distribution Network Service Provider
De-rating	Assigning a lower rating for an item of plant
DFA	Distribution Feeder Automation. Remote switching of the HV network with the main purpose of transferring load between feeders rapidly
Discounting	The conversion of the value of a cost or benefit at some later point to time to its present value
Discount Rate	The indicated rate to be used in the discounting process – typically the WACC
Distribution	Overhead lines and underground cables exiting a zone substation including all equipment connected to these lines. These are operated at 22kV, 11kV or 6.6kV

TERM	DEFINITION
Diversity Factor	A multiplier that is used to take into account non-coincident demands at multiple points when aggregating these figures. Failure to use a diversity factor will result in an overestimate of the aggregated demand
DOL	Direct on-line switching of motors at full voltage
Double Circuit:	Two circuits with the same voltage on the same pole line
Double Contingency:	The occurrence of two events so close together that no corrective action can be taken before the second event occurs, e.g. a fault followed by a circuit breaker failure or a double circuit line outage.
Dropper	A piece of conductor between the substation bus and the start of the feeder conductor. Upgrading these conductors is usually economic above (N-1) rating
DSS	Distribution System Augmentation Program. Annual program to address overloaded distribution substation and LV circuits
DVMS	Dynamic Voltage Management System
Dynamic Wind Ratings	Under certain weather conditions, the rating of some overhead lines can be increased due to the cooling effect of the wind.
EENS	Expected energy not supplied is another interpretation of reliability based on load not supplied rather than customer numbers
Exclusive Switching Zone	Has only one customer/substation supplied from the section of feeder.
Exit Cable	The cable connected to the feeder circuit breaker that leaves the boundary of the zone substation.
Feeder	Transports power from the zone substation to the distribution substations and HV customers
Fixed Capacitors	The capacitor is switched on all the time
Full Transformer Switching with Line Breakers	Full switching flexibility, has the benefit of both fully and Non-Fully switched stations
Fully Switched Station	Each transformer at the zone substation has CBs somewhere in the system which can automatically isolate that transformer should a fault occur without interrupting supply to the station. vis. there is at least a 22kV Transformer CB and a 66kV CB either at the station or remote at the Terminal or other Zone Substation
HV	High voltage, 11, 22 or 6.6kV. Used interchangeably with MV.
Jumbo Feeder	A feeder with an abnormally high rating.
Lagging Power Factor:	Where the active power and reactive power flow in the same direction.
Line Breakers:	Circuit breakers between the sub-transmission lines and the zone substation bus

TERM	DEFINITION
Load Duration Curve:	A cumulative plot of demand against percentage of the time period. It is interpreted as the percentage of time above a certain demand and usually contains data for an annual period
Load Factor	The ratio of average power in MW (energy purchases in MWh divided by 8766) to maximum demand power in MW for a single year. A unity load factor indicates a flat load profile
Load Transfer	Connecting distribution substations to other feeders by changing open point positions
Loading	The amount of current flowing through an item of plant
Losses	The amount of power dissipated as heat from an item of plant
Loss Factor	The multiplier used to convert metered energy to metered energy plus losses. Where the losses are zero, the loss factor would be unity
LV	Low voltage, 230V single phase or 400V three phase
Major Switching Zone	A major switching zone is a section of feeder which may be switched safely at any time by primary switching. Such a section of feeder would be located between switching devices with the necessary load break capability.
Minor Switching Zone	A minor switching zone is a section of feeder which may only be switched safely by primary switching after preparatory switching procedures. Such a section of feeder would be located between a switch and an isolator.
MD	Maximum demand. The highest value of Ampere, MVA or MW in any year. For distribution feeders, zone substations and sub-transmission lines, MD uses the instantaneous SCADA Ampere data except in instances where there is traction load (or short time fluctuating loads). In these instances, 5 minute average loading should be used in calculating MD. For distribution substations, LV circuits and transmission connection assets, MD uses the half-hourly average interval metering data
Multiple Contingency	The occurrence of some catastrophic event, e.g. spread of transformer fire to adjacent transformers.
(N) Cyclic Rating	The highest summed transformer cyclic nameplate rating of the zone substation. This is the maximum level a zone substation can be loaded. Often referred to as the (N) Rating.
(N-1) Criterion	A deterministic planning philosophy which provides sufficient capability such that for loss (planned or forced) of any single element (line, transformer, circuit breaker, busbar, etc.) at the time of maximum demand, the voltages and loading on all remaining in-service elements are within their design limits/ratings for the duration of the outage. This philosophy provides 100% backup at all times and is a no risk approach for single contingency events

TERM	DEFINITION
(N-1) Cyclic Rating (CR)	The daily peak summed transformer output to which a zone substation may be subjected for a period of up to three months when a critical element, e.g. a transformer, is out of service. A transformer may be cyclically loaded in such a way that periods of overloads are followed by period of light loads and the life expectancy will not be reduced if the accelerated rate of deterioration of the insulation during the heavily loaded periods is counterbalanced by the decelerated rate of deterioration during the lightly loaded periods. This gives a loss of life per cycle of 0.03% based on a 30 year transformer lifetime.
(N-1) Limited Cyclic Rating (LCR)	The permissible peak summed transformer output to which a zone substation may be subjected over one daily load cycle following the outage of a critical element, after which the affected element must be returned to service or the summed transformer output must be reduced to the zone substation's Cyclic Rating. This is the loading that is permissible for only a 24 hour period during first order contingency conditions. It is 110% of the cyclic rating and will result in a slightly accelerated loss of life/cycle.
(N-1) 2 Hour Emergency Rating (2hr ER)	The permissible peak summed transformer output to which a zone substation may be subjected over two hours following the outage of a critical element, after which the affected element must be returned to service or the summed transformer output must be reduced to the zone substation's Limited Cyclic Rating. This is the loading that is permissible for only a 2 hour period during first order contingency conditions. It will result in a slightly accelerated loss of life/cycle.
(N-1) 10 Minute Emergency Rating (10min ER)	<p>The permissible peak summed transformer output to which a zone substation may be subjected over 10 minutes following the outage of a critical element, after which the affected element must be returned to service or the summed transformer output must be reduced to the zone substation's Two Hour Emergency Rating. This is the loading that is permissible for only a 10 minute period during first order contingency conditions. It will result in an accelerated loss of life/cycle.</p> <p>The 10 minute rating available under the following conditions:- i) DFA scheme is in place to transfer sufficient amount of load to other stations within 10 minutes; ii) Customer load shedding or standby generation in place to cover loss of plant</p>
NCC	Network Control Centre
NER:	Neutral Earth Resistor. Connected between transformer star point and earth to limit phase to ground current
Non Fully Switched Station	No circuit breakers on transformers. Line side circuit breakers on sub-transmission. Transformers at the zone substation are in one bank and a fault in any one of them, (or on the open bus-work) will shut down the whole station. Such stations are not subject to sub-transmission line failures where the sub-transmission line is operating within the (N-1) rating.
NLM	Network Load Management. Calculation and reporting tool used to aggregate smart meters half-hourly data at key level in UE network from LV circuit to 66 kV bus of the terminal station. Also reports peak demand daily and seasonally at all network levels



TERM	DEFINITION
NPV	Net Present Value. Projects with a final year NPV greater than zero are economic. NPV is effective the Present Value of Benefits less the Present Value of Costs and is expressed in Dollars
OLTC	On-Load Tap Changer. The mechanism attached to the transformer that changes the tap position in response to the signal from the VRR
OOS	Out of service
Open Point	A switch on a distribution feeder that is in the open state
OSSCA	Overload Shedding Scheme for Connection Assets (A control system used to trip sub-transmission loops in the event of a terminal station overload)
PAS	Project Authorisation Sheet. A design approval form submitted by the Service Provider to Service Delivery for approval to commence construction also known as a minor statement of work.
Point of Connection	Connection between transmission assets and UE assets.
Power Factor	The ratio of active power to apparent power. A unity power factor indicates no reactive power in the element
Present Value	The value of a cost or benefit in the future, discounted to today's value
PSS/Sincal, PSS/U or PSS/E	Power System Simulator. The stand-alone product and engine integrated into AM/FM are available with this application
Reconductoring	Replacing a piece of conductor with another usually of higher rating
Regulatory	Rules by which UE as constrained to operate legally
Reliability	A measure of the service that is provided to customers in terms of reliability of power
Relocatable Transformer	A transformer that can be transported quickly between stations in an emergency. A relocatable unit is mounted on a transport vehicle with isolating equipment and connections.
SAIDI	System average interruption duration index = total number of customer minutes off supply divided by number of customers served
SAIFI	System average interruption frequency index = total number of customer interruptions divided by number of customers served
SCADA	Supervisory Control and Data Acquisition System. Used to operate the network from a remote control room
Schematic Diagram	A single line representation of the geographic diagram compressed for simpler interpretation. This diagram is not to scale.
Second Order Contingency	The occurrence of a single outage, either forced or planned from an abnormal system condition in which a single contingency situation already exists
Single Contingency	The occurrence of a single outage, either forced or planned, from the normal condition which, for design purposes, is taken as all lines and plant in service.

TERM	DEFINITION
SOCS	System Overload and Control Scheme: A control system used to monitor the dynamic rating of transmission lines
Software	Computer applications to model the power system
Substation	A distribution transformer. These are operated at 22kV, 11kV or 6.6kV and provide a secondary voltage of 400V
Sub-transmission	Overhead lines and underground cables connecting terminal stations to zone substations. These are operated at 66kV or 22kV
SWER	Single wire earth return. 12.7kV single phase lines used in rural areas. An isolating transformer exists between the HV feeder and the SWER line
Shared Network	The transmission system excluding connection assets
STPIS	Service Target Performance Incentive Scheme
System Normal	All equipment defined as normally in service is in service
Temperature Switched Capacitors	The capacitor is switched on when the ambient temperature reaches a certain value
Terminal Station	Sites where transmission voltages are transformed down to sub-transmission voltages. These sites are not owned by UE, but the connection assets within the terminal stations are planned by UE.
Time Switched Capacitors	The capacitor is switched on and off according to the time of day and day of week
Transfer Capability	The amount of load that can be transferred to other feeders on other zone substations
Transformer Switching Levels	The amount of switching flexibility in a zone substation. This is a primary factor in determining the reliability or risk of a zone substation
TUOS	Transmission Use Of System charges. This is a payment that is made by each DNSP for using the transmission network.
Upgrade	Increasing the rating of a piece of equipment by replacing it with equipment of a higher rating
Up-rating	Increasing the rating of a piece of equipment based on a review (paper up-rate) and/or adjustment of the existing installation
URD	Underground residential development
Utilisation	The current flowing through an item of plant expressed as a percentage of its rating. Utilisation can be expressed in terms of the N or (N-1) cyclic, limited cyclic or emergency ratings. For distribution feeders, zone substations and sub-transmission lines, utilisation uses the instantaneous SCADA Ampere data except in instances where there is traction load (or short time fluctuating loads). In these instances, 5 minute average loading should be used in calculating utilisation. For distribution substations, LV circuits and transmission connection assets, utilisation uses the half-hourly average interval metering data

TERM	DEFINITION
VAr Switched Capacitors	The capacitor is switched on and off according to the reactive power flowing down the line.
Voltage Control	Regulating the voltage through transformer tapping
VCR	Value of Customer Reliability
VRR	Voltage Regulating Relay. Constantly monitors the bus voltage level at the Zone Substation and initiates tap changes
WACC	Weighted Average Cost of Capital
XLPE	Cross-linked Poly-ethylene cable
Zone Substations:	Sites where sub-transmission voltages are transformed down to distribution voltages. These sites are owned by UE.












# UE GU 2200 Network Planning Guidelines

Final Audit Report

2019-08-08

Created:	2019-08-06
By:	Christopher Roberts (christopher.roberts@ue.com.au)
Status:	Signed
Transaction ID:	CBJCHBCAABAAGa--RmnrINYGKIFt0TE2qsu5aRI88q

## "UE GU 2200 Network Planning Guidelines" History


-  Document created by Christopher Roberts (christopher.roberts@ue.com.au)  
2019-08-06 - 23:43:23 GMT- IP address: 202.125.86.197
-  Document emailed to Sujeewa Vithana (Sujeewa.Vithana@ue.com.au) for signature  
2019-08-06 - 23:44:20 GMT
-  Email viewed by Sujeewa Vithana (Sujeewa.Vithana@ue.com.au)  
2019-08-07 - 00:00:30 GMT- IP address: 202.125.86.197
-  Document e-signed by Sujeewa Vithana (Sujeewa.Vithana@ue.com.au)  
Signature Date: 2019-08-07 - 00:00:51 GMT - Time Source: server- IP address: 202.125.86.197
-  Document emailed to Roshanth Sivanathan (Roshanth.Sivanathan@ue.com.au) for signature  
2019-08-07 - 00:00:55 GMT
-  Email viewed by Roshanth Sivanathan (Roshanth.Sivanathan@ue.com.au)  
2019-08-07 - 00:05:21 GMT- IP address: 202.125.86.197
-  Document e-signed by Roshanth Sivanathan (Roshanth.Sivanathan@ue.com.au)  
Signature Date: 2019-08-07 - 00:05:36 GMT - Time Source: server- IP address: 202.125.86.197
-  Document emailed to Christopher Roberts (christopher.roberts@ue.com.au) for signature  
2019-08-07 - 00:05:39 GMT
-  Email viewed by Christopher Roberts (christopher.roberts@ue.com.au)  
2019-08-07 - 00:06:31 GMT- IP address: 202.125.86.197
-  Document e-signed by Christopher Roberts (christopher.roberts@ue.com.au)  
Signature Date: 2019-08-07 - 00:06:56 GMT - Time Source: server- IP address: 202.125.86.197
-  Document emailed to Ashish Gupta (Ashish.Gupta@ue.com.au) for signature  
2019-08-07 - 00:06:59 GMT

 Email viewed by Ashish Gupta (Ashish.Gupta@ue.com.au)

2019-08-07 - 00:07:32 GMT - IP address: 202.125.86.197

 Document e-signed by Ashish Gupta (Ashish.Gupta@ue.com.au)

Signature Date: 2019-08-07 - 00:07:46 GMT - Time Source: server- IP address: 202.125.86.197

 Document emailed to Rodney Bray (rodney.bray@ue.com.au) for signature


2019-08-07 - 00:07:49 GMT

 Email viewed by Rodney Bray (rodney.bray@ue.com.au)

2019-08-08 - 02:45:50 GMT - IP address: 1.152.108.202

 Document e-signed by Rodney Bray (rodney.bray@ue.com.au)

Signature Date: 2019-08-08 - 02:46:19 GMT - Time Source: server- IP address: 1.152.108.202

 Signed document emailed to Rodney Bray (rodney.bray@ue.com.au), Roshanth Sivanathan (Roshanth.Sivanathan@ue.com.au), Christopher Roberts (christopher.roberts@ue.com.au), Ashish Gupta (Ashish.Gupta@ue.com.au) and 1 more

2019-08-08 - 02:46:19 GMT