ELECTRICITY NETWORKS

DISTRIBUTION SYSTEM AUGMENTATION PLANNING POLICY AND GUIDELINES

CONTENTS

1 INTRODUCTION

This document provides the criteria on which the Powercor and CitiPower Distribution Businesses undertake demand related augmentation on the distribution system. It is an executive endorsed policy that outlines the rules applied by each business regarding the identification of terminal station connection asset and distribution network constraints and the long term investment and development to meet forecast electricity demand.

This document is critical in regards to the businesses core functions as a Distribution Network Service Provider (DNSP), and is used to fundamentally support forecast connection asset, network and non-network related capex projections within the regulated environment.

A further two system augmentation related documents directly relating to the distribution network are subsidiary to this main policy document. These documents are the High Voltage and Low Voltage Augmentation Planning Policy and Guidelines.

2 PLANNING POLICY OVERVIEW

2.1 OVERALL OBJECTIVE OF DISTRIBUTION SYSTEM AUGMENTATION PLANNING

The planning standards and criteria applied in the development of the distribution system are a significant determinant in regards to managing load-related risks and constraints associated with connection and network assets. Such constraints directly impact on the investment or capital expenditure levels that may be required given various demand growth scenarios.

The Distribution System Augmentation Planning Policy and Guidelines shall be interpreted and implemented to ensure the following objectives are met:

- The system can be operated in a safe manner and that risk to employees and the public is minimised and controlled wherever possible.
- The cost of augmentation or rearrangement of the Distribution System is optimised to deliver benefits to all stakeholders by using long term, minimum cost, technically acceptable solutions that maximise benefits to the consumer.
- Synergies with asset management plans from the connection asset owners and that of CitiPower and Powercor are identified and implemented where cost effective.
- Non-network alternatives to augmentation are given due consideration. Such alternatives include, but are not necessarily limited to, demand-side management and embedded generation.
- Connection and Network Assets are to be operated in a reliable and secure way to maximise supply to customers without damaging plant. Run-to-failure approaches are to be minimised and utilisation of assets is to be maximised in a prudent and efficient manner.
- To deliver a systematic, transparent, and robust approach to ensure the early identification of existing and future system constraints on a ‘no-surprises’ basis.

These guidelines specifically aim to support the distribution service theme of the company vision by:

- Reinforcing security and reliability of supply.
- Ensuring standards for the operation of the network are met.
- Promoting standardisation of augmentation design.
- Promoting a whole of business approach to the planning and design of the network.

Powercor and CitiPower are committed to improving the reliability and quality of supply through automation of the distribution network. Consistent with the policy of facilitating improved customer supply performance, consideration shall be given and provision made for remote operation and/or automation of the distribution network when augmentation or asset replacement works are carried out in a prudent, economic and efficient manner.

2.2 OVERALL APPROACH TO SYSTEM PLANNING AND INVESTMENT EVALUATION

Powercor and CitiPower take into account a probabilistic approach when planning the distribution system development.

Prescribed planning periods vary from 5 years for the Distribution Annual Planning Report (DAPR) to 10 years for the Transmission Connection Planning Report (TCPR) and up to 25 years for specific strategic area based studies.

Under this probabilistic approach, the N-1 strict deterministic criterion which requires zero interruptions to customer supply is relaxed, and simulation studies are undertaken to assess and value the amount of load and energy that would not be supplied if an element of the network were out of service. The reduction in customer value of the energy at risk brought about by a potential project or investment stream is then compared to the cost of the augmentation in an economic analysis to determine the best project option that maximises benefits to the consumer.

The application of this approach provides some degree of flexibility in regards to investment timing based on the exposure and risk of loss of supply to customers after network outages. Applied in a considered manner, it can lead to the deferral of significant network capital works that would otherwise proceed if a prescriptive deterministic standard were strictly applied, especially in an environment where the demand growth levels are low to moderate as opposed to relatively high. (A deterministic approach to N-1 defines that capacity must be added to meet the total maximum load forecast with one network element out of service).

In addition, the probabilistic approach assesses unserved load and energy under the ‘system normal condition’ or ‘N’, which is where all assets are operating but load exceeds the total capacity.

This probabilistic approach involves consideration of the likelihood of a plant outage coinciding with the peak loading season and the consequence of that outage.

Implicit in this approach is acceptance of some degree of risk that there may be circumstances when the capacity of the connection or network assets will be insufficient to meet actual or forecast demand and that there will be constraints to the supply of electricity to customers. The extent to which investment should be committed to mitigate any risk is ultimately a matter of judgment, having regard for technical, social and economic matters such as:

- The potential costs and other impacts that may be associated with very low probability events, such as single or coincident transformer outages at times of peak demand, and catastrophic plant failure leading to extended periods of plant non-availability;
- The anticipated cost of technically acceptable network and non-network solutions compared with the benefits of reduced load or energy at risk levels;
- The type and nature of customers affected by potential outages, as well as the frequency and duration of the any loss of supply; and
- The availability or technical feasibility of cost-effective contingency plans and other arrangements for management and mitigation of risk.

For all projects aimed at alleviating a system constraint, the prudence and efficiency of network investment decisions, should be made having regard to:

- The relative costs and benefits to end consumers, including any change in supply reliability, of connection asset network augmentation and non-network alternatives to augmentation;
- The uncertainty and or sensitivity of the assumptions that must necessarily be made in the decision analysis;
- The objective of minimising total life-cycle costs;
- The need to comply with environmental and land-use planning standards, health and safety standards and applicable technical standards, all other relevant Acts and Regulations and
- Augmentation of the system in a way which takes into account and minimises losses, and resultant greenhouse gas emissions, where it is economical to do so.

As such, for the distribution network, pre-defined planning criteria will be used as the basis for determining required augmentation up to $1million project value. Above this threshold of $1million for distribution network or for any value connection asset project, an economic analysis will be used as well where there is no other Rule or Code compliance issue.

Above a threshold of $5million, a Regulation Investment Test – Distribution (RIT-D) will be applied to determine the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

Where Connection Asset projects are identified by Powercor/CitiPower and there is a transmission network investment required that is greater $5milllion, the Regulation Investment Test – Transmission (RIT-T) is to be used.

Timing of augmentation will take into account factors including those above as well as:

- Confidence of continued demand on the asset;
- The prospect of system or non-network developments which would impact long term need for augmentation;
- Economic growth rates;
- Council development plans;
- Housing development policy; and
- Major customer activity.

Any departure from the documented planning criteria (irrespective of whether this leads to the prudent and efficient advancement or deferral of expenditure) will be subject to a risk assessment and approval by the Network Planning and Development Manager.

Network high voltage distribution assets are categorised into ‘Urban’, ‘Rural’, ‘CBD’ and ‘SWER’ for the purpose of planning criteria and investment analysis.

As standard planning practice, project and augmentation timing will always take into account the available network capacity to transfer load away from an over utilised asset after an outage – refer to Distribution Load Transfers.

Annual contingency planning is undertaken as an emergency response to keep customers on supply as a day to day means to maintain customer’s expectations as part of the Annual Planning Process (see section 2.5).

2.3 PLANNING OBLIGATIONS

Both Powercor and CitiPower have formal statutory planning obligations under the Distribution Licences, National Electricity Rules, the Electricity System and Electricity Distribution Codes. The references to various clauses and sections of the above obligations are detailed below:

Distribution Licence

- Clause 11 requires compliance to the Distribution and System Codes.

The National Electricity Rules (NER):

- Clause 4.2.3 and S5.1.2.1 refer to definitions of credible contingencies.
- Clause 5.10.2 defines network development generally and in particular sets out when a RIT-D or RIT-T is required.
- Clause 5.11 refers to forecasts of connection to transmission network and identification of system limitations
- Clause 5.13 refers to the Distribution annual planning process and includes the requirement to prepare forecasts and identify limitations and corrective action including the need for and Regulatory Investment Test for Distribution (RIT-D) and a Demand Side Engagement Strategy containing the information required in S5.9 of these Rules
- Clause 5.13.2 refers to the requirement to publish a Distribution Annual Planning Report containing information as required in S5.8 of these Rules
- Clause 5.13A refers to the provision of zone substation information
- Clause 5.14.1 refers to joint planning obligation between Transmission Network Service Providers (TNSPs) and Distribution Network Service Providers (DNSPs)
- Clause 5.14.2 refers to joint planning obligation between Distribution Network Service Providers (DNSPs) and Distribution Network Service Providers (DNSPs)
- Clause 5.15 refers to the requirements for Regulation Investment Tests generally

- Clause 5.16 refers to the requirements for Regulation Investment Test – Transmission. In particular Clause 5.16.3(a)(2) sets the threshold for where a RIT-T is required at presently $5million of transmission investment associated with a connection asset project.

- Clause 5.17 refers to the requirements for Regulation Investment Test – Distribution. In particular Clause 5.17.3(a)(2) sets the threshold for where a RIT-D is required at presently $5million of distribution investment required.

- Schedule 5.1a refers to system standards.

- Schedule 5.1 refers to network performance requirements - of particular note are S5.1.2.2 (network service within a region) and S5.1.10.2 (load and network control facilities).

- Clause 5.2.3 sets out obligations of network service providers of which a distribution business is

- Schedule 5.8 refers to the information requirements to be included in a Distribution Annual Planning Report

- Schedule 5.9 refers to the information requirements to be included in a Demand Side Engagement Document

<u>The Electricity System Code (ESC):</u>

- Clause 281 refers to annual Transmission Connection Planning Reports (and ten year planning horizons).

<u>The Electricity Distribution Code (EDC):</u>

The following clauses remain in the EDC but have been superseded by Clause 5.13 of the NER. Note that the TCPR is still required by the ESC.

- Clause 3.4 refers to the annual Transmission Connection Planning Report (TCPR).

- Clause 3.5 refers to the annual Distribution System Planning Report (DSPR).

2.4 ANNUAL PLANNING PROCESS

The Annual Planning Process involves the following major steps in a business process referred to as The Planning Cycle:

- The determination of ten-year terminal station load forecasts using previous terminal station summer and winter demands and projecting forward based on expected growth rates which take into account a range of factors including past growth, economic outlook and future area developments and trends. The forecasts are done on a 50% and 10% Probability of Exceedence (PoE) basis by using temperature corrected actual data over a long period of time, then projecting forward using probability analysis techniques. Typically these forecasts are provided by external economic research agencies. The majority of planning studies are based on 50% PoE forecasts except when load is approaching N capacity on the basis of 10% PoE forecasts.

- The determination of feeder and zone substation load forecasts using previous feeder and zone substation demands and projecting forward based on expected growth rates, known new loads and developments and then adjusting to meet the externally provided and economically driven terminal station forecasts. This is referred to as a 'top down-bottom up' approach and aims to produce more informed and accurate forecasts using both external and internal knowledge, skills and data.

- Terminal Station forecasts are provided to the Australian Energy Market Operator (AEMO) and published in the TCPR. Distribution forecasts are published annually in the DAPR.

- The confirmation of zone substation and line ratings.

- The assessment of load effects on system performance. This involves an analysis of steady-state (N) and credible single contingency (N-1) load, fault level and voltage conditions by system modelling using computer load-flow and fault level programs (PSS/E, SINCAL etc). The time load is at risk i.e. excess above single contingency capacity, is assessed using known yearly interval load data against capacity over a 10 year forecast period.

- The development of options for augmentation to meet forecast load growth and system requirements. Some of the options to defer augmentation include permanent load transfers, thermal re-rating and plant protection (load shed) schemes.

- The technical and economic analyses of augmentation options, including any available network, non-network and demand management proposals.

- The preparation and amendment of ten-year plans for terminal station connection assets, zone substations and line works augmentation and related documentation. A planning strategy is developed for each major asset. Planned yearly augmentation work is prioritised in terms of risk.

- Terminal station connection and Distribution asset augmentation plans are published annually in the TCPR and DAPR respectively. Changes to terminal station connection asset bus voltage settings, system arrangements and ties between terminal stations that affect fault levels or subtransmission loop changes that affect load shedding plans are communicated annually to AEMO.

- The determination of operational contingency plans for both Terminal station connection assets and Distribution assets using 10% PoE forecasts to cater for forced outage of major plant during critical loading periods in the following year.

- Terminal Station Connection Assets are jointly planned with AEMO and the Distribution Network Service Providers (Distribution Businesses) that are supplied from the connection assets and the Transmission Network Service Providers that own and maintain the assets.

- Distribution assets that supply more than one Distribution Business are jointly planned.

2.5 RELATED DOCUMENTS AND PROCESSES

Other critical documents and processes support an integrated approach taken to augment the network with other business practices. These processes include the annual State of the Network reporting, capital governance/approval process, detailed project reviews, 10% PoE and 50% PoE demand forecasting, design standards, financial NPV analysis, project cost estimating and management and environmental considerations.

2.5.1 Environmental Planning Considerations

The Network Planning process shall consider all environmental issues as defined in the CP & PAL Environmental Policy (16-00-CP0001) and Environmental Manual (16-10-CP0004) to ensure that:

- Operations comply with environmental legislation and regulations.
- Our activities and assets incur minimal environmental damage.
- For zone substation establishment, new Subtransmission lines or significant green field Distribution lines an Environmental Impact Assessment (EIA) is to be developed in consultation with the Environmental group.
- Long-term strategic decisions take into account the opportunity to use materials and resources in a sustainable manner in order to maximise the benefit for future generations.
- Our reputation is enhanced as an effective environmentally-focussed business.
- Losses are minimised.
- We consult with stakeholders on key environmental issues that are relevant to our activities and assets.
- The principles of continual improvement, pollution prevention and waste minimisation are applied. Note: Technical standard SA -051 for “Oil Containment”.
- The Green Purchasing Policy principles are followed during procurement and purchasing.
- Any upgrade or network augmentation addresses and rectifies any possible EMF and noise related complaints. Refer to Technical standard DA -231 for “EMF and Noise”.
- Greenhouse gas emissions are minimised.
- Impact on native fauna and flora is minimised.

2.6 PLANNING POLICY OVERVIEW

An overview of CitiPower and Powercor planning policy is provided in the following table, which summarises the respective planning criteria for defined asset types. This summary should be considered in conjunction with the descriptions provided in sections 3 to 5 of these guidelines. Note that for distribution network projects greater than $1million, the economic criteria must also be satisfied unless other overriding factors such as compliance to the NER or EDC are present.

In the table below:

- #Dynamic refers to Dynamic (real time) Line Rating.
- *Maximum Load is 50% PoE forecast load, Rating is continuous for lines and cyclic for substations.

- ^Plant Protection refers to a Plant Protection (load shed) Scheme.

Asset			Planning Criteria Trigger to Review					
Type	**Format**	**Section**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**	**Load Control Scheme**	**Maximum Load* as % of Rating**	**Maximum Time over Rating, Hours**
Connection Asset	Single Transformer Terminal Station (Rural)	3.3.1.1	<30MVA	N	Best Practice	^Plant Protection	100	0
	Multiple Transformer Switched Terminal Station	3.3.1.2	Any	N-1	<1 minute	^Plant Protection	110	120
Subtransmission lines	Radial Overhead Line (Rural)	4.3.1.1	<20MVA	N	Best Practice	N/A	100	0
	Looped Line (Rural and Urban)	4.3.1.2	>20MVA	N-1	<1 minute	^Plant Protection	120	120
	Meshed Cable Enhanced Security (CBD)	4.3.1.3	Any	N-2 after 30 minute switching	<1 minute	N/A	120	120
Sub transmission zone substations	Single Transformer Zone Substation (Rural)	5.3.2.1	<15MVA	N	Best Practice	N/A	100	0
	Multiple Transformer Banked Zone Substation (Rural)	5.3.2.2	15-20MVA	N-1	<4 hours	N/A	110	120
	Multiple Transformer Switched Zone Substation (Rural and Urban)	5.3.2.3	>15MVA	N-1	<1 minute	^Plant Protection	110	120
	CBD Zone Substations	5.3.2.3	>15MVA	N-1	<1 minute	N/A	100	0
Distribution lines	Radial Line (Rural Short & Rural Long)	6.2.1	Any	N	Best Practice	N/A	100	0
	Looped Line (Rural Long)	6.2.2	Any	N-1 Partial	Best Practice	N/A	80	0
	Looped Line (Urban & Rural Short)	6.2.3	Any	N-1	Best Practice	N/A	67	0
	Looped Line (Urban - CitiPower)	6.2.3	Any	N-1	Best Practice	N/A	67	0
	CBD Underground Cable	6.2.4	Any	N-1	Best Practice	All in group except 1	100	0
						1 x standby	0	0
Sub Trans lines and Zone Subs	Economic Criteria	>$1M Project value	The Annualised Cost of the Capital Project is less than the reduction in Annual Value of Expected Energy at Risk					

3 CONNECTION ASSETS

3.1 DEFINITION OF A CONNECTION ASSET

The connection asset is the 220kV to 66kV transformers and associated 66kV bus and switchgear at a terminal station owned by a Transmission Network Service Provider. It may also include 220kV switchgear if defined by AEMO as connection assets. Also 220kV to 22kV transformation and associated busses and bus tie circuit breakers are also connection assets. Connection Assets are used to supply a distribution network. A connection asset is part of a Transmission System that also contains a transmission network. In terminal stations with 220/22kV transformation, 22kV circuit breakers to supply subtransmission lines are also connection assets while circuit breakers supplying customers are defined as distribution assets.

3.2 PLANNING RESPONSIBILITY

In Victoria, the responsibility for planning of Connection Assets is with the Distribution Network Service Providers. In CitiPower/Powercor, the Subtransmission Planning group carries out connection asset planning in conjunction with other affected distribution businesses and transmission network service providers (including AEMO).

3.3 PLANNING CRITERIA FOR AUGMENTATION

3.3.1 Terminal Station

A terminal station provides the voltage transformation from the transmission system (normally operating at 220kV) to the subtransmission or distribution network (normally operating at 66kV or 22kV). The terminal station also provides the voltage regulation to maintain the distribution network connection point voltage levels within the Electricity Distribution Code requirements.

To determine when augmentation is required there are Common Criteria applicable to all Zone Substations:

Augmentation should be considered when any of the following Common Criteria cannot be met.

- Load to be kept within 110% of station firm (N-1) cyclic rating, after taking into account all feasible distribution load transfers to adjacent stations providing the load of the other stations are also under 110% of firm (N-1) cyclic rating.
- Fault level to be within distribution code obligations.
- Voltage to meet distribution code.

Augmentation timing is determined by station firm (N-1) cyclic rating, the capacity of distribution load transfers, customer load type (commercial, industrial or residential) and level of customer load at risk above 100% of firm capacity but not before it is justified economically.

Asset renewal due to age and/or condition is to be determined by the asset owner and when required, an overall review of augmentation and replacement strategies considered.

3.3.1.1 Single Transformer Terminal Station

ASSUMPTION:

For loss of the transformer, the customers are interrupted before switching onto alternative supply using 66kV tie lines between terminal stations (provided this does not impact on system security or voltage levels).

APPLICATION:

For remote rural locations.

For loads up to 30MVA.

SPECIFIC CRITERIA FOR AUGMENTATION:

An augmentation project is identified for analysis when load exceeds 20MVA after transfers away or the normal (N) cyclic rating of the station.

3.3.1.2 Multiple Transformer Switched Terminal Station

ASSUMPTION: For loss of a transformer, the whole load transfers to the remaining transformer/s. No interruption to customers unless a contingency load shedding scheme is in place.

APPLICATION: Multiple transformer terminal stations are applicable for loads in excess of 20MVA after transfers away.

SPECIFIC CRITERIA FOR AUGMENTATION:

An augmentation project is identified when:

- The forecast load exceeds the station firm cyclic rating and the excess load is unable to be transferred away automatically.
- If an automated load transfer scheme is installed, the station can be loaded above firm cyclic rating by the amount of automatic transfers available.
- Installation of a plant protection (load shed) scheme may be considered for load above N-1 where a major augmentation cannot be economically justified.
- If a Plant Protection (Contingency Load Shed) scheme is installed, augmentation is to be considered when the load at risk is at least 10% above firm cyclic rating for more than 120hrs per year after transfers away.

4 SUBTRANSMISSION NETWORK

4.1 DEFINITIONS

4.1.1 Definition of Subtransmission Network

A subtransmission network starts at the connection to the Terminal Station and end at the transformer higher voltage connection in a Zone Substation. Subtransmission networks include subtransmission lines, cables and 66kV or 22kV (CitiPower 22/11 or 22/6.6kV zone substations only) switchgear. The connecting link between the terminal station and the zone substation is referred to as the subtransmission line or cable and is usually at a nominal voltage of 66kV or can be 22kV in some circumstances in CitiPower. The Subtransmission Planning group plans network investment on subtransmission lines.

4.1.2 Shared Subtransmission Networks

Where the subtransmission network incorporates the assets of more than just CitiPower or Powercor then this system is referred to as a shared subtransmission network. For example a 66kV network shared with Jemena is the Keilor-Melton-Gisborne-Woodend-Sydenham-Sunbury 66kV network. (Sunbury and Sydenham zone substations, Keilor-Sunbury and Keilor-Sydenham-Sunbury 66kV lines are Jemena assets). Ownership of these assets is defined in the Distribution System Agreement between Powercor and Jemena.

4.2 PLANNING CRITERIA FOR AUGMENTATION

4.2.1 Subtransmission Overhead Lines and Underground Cables

Subtransmission overhead lines and underground cables are usually connected at the 66kV or 22kV bus of a terminal station. Subtransmission lines are normally constructed using pole lines and operated at 66kV or 22kV. However, in special circumstances, some subtransmission lines are constructed with steel lattice tower supports. Subtransmission cables are used in heavily built up areas at 66kV or 22kV, and are especially common in CBD areas.

These lines and cables form the system links between transmission connection assets and zone substations and between the zone substations. Although they have a variety of configurations they are designed in either a radial, loop or mesh topology.

An augmentation project is initiated when the forecast load exceeds the summer or winter thermal ratings of the line with timing of the augmentation determined by the extent of the thermal overloading and level of the customer load at risk considering customer load type and magnitude.

The following Common Criteria are applicable to all Subtransmission lines and cables for system normal and N-1 credible contingency events. Specifically, where non-compliance with any item within the criteria is identified, this is to be taken as a trigger for the business to undertake a detailed investigation into the network constraint and potential alternatives and investment needs:

- Operational load to be kept within the limits of the line or cable (as defined below).
- Operational load above line rating never to exceed 20%.
- For system normal, underground cable operational load is not to exceed cyclic ratings.

- For the purposes of selecting whether a day-time or night-time overhead line rating is used, the following definitions are applicable:
  - Day-time ratings apply when the most recent historical record of line maximum demand occurs between 0600 – 2100 hrs in summer or 0700 – 1900 hrs in winter.
  - Night-time ratings apply when the line maximum demand occurs between 2100 – 0600 hrs in summer & 1900 – 0700 hrs in winter.
- Operational load above overhead line rating never to exceed the Limited Cyclic (Emergency) rating.
- For credible N-1 contingency events, load above cable rating never to exceed the Short Time Emergency cyclic ratings (24hours or less). Typically this is between 15-20% above the cyclic rating. For longer outages, the cable cyclic or continuous rating (whichever is applicable to the load type) is not to be exceeded.
- Fault level not to exceed line and cable fault ratings.
- Voltage to meet Distribution Code.

4.2.1.1 Radial Subtransmission Lines

ASSUMPTION:

Any planned or unplanned outage of the line results in a supply interruption to customers. Therefore, when a fault occurs, as much load as feasible is transferred to adjacent zone substations.

The maximum thermal rating of an overhead line is 80°C provided no other system limitation applies.

APPLICATION:

This philosophy is applicable to radial lines in rural areas with a forecast maximum demand of less than 20MVA.

SPECIFIC CRITERIA FOR AUGMENTATION:

An augmentation project is identified when:

- Load exceeds thermal rating of the overhead line provided no other system limitation applies.
- Time above rating exceeds 80 hrs per year.
- Augmentation to loop arrangement is to be considered if the forecast peak summer demand on the radial line exceeds 20MVA.

4.2.1.2 Loop Subtransmission Lines

ASSUMPTION: Planned and unplanned outage of one line in a loop arrangement does not result in a supply interruption to customers. The full load is carried by the remaining lines in service.

The maximum thermal rating of an overhead line is 100°C provided no other system limitation applies.

In general, the maximum thermal ratings for underground cables are 90ºC for xlpe, 105ºC for EPR and, 65°C-70ºC for paper insulation provided no other system limitation applies.

APPLICATION: This philosophy is used for servicing all loads above 20MVA that cannot be backed up from other sources (except for the Melbourne CBD – refer to section 3.3.1.3).

SPECIFIC CRITERIA FOR AUGMENTATION:

An augmentation project is identified when:

- Augmentation is based on load exceeding thermal line limits for one line in the loop out of service (N-1 contingency).
- Load exceeds thermal rating of the overhead line or cable provided no other system limitation applies.
- Time load above line thermal rating exceeds 120 hrs per year.
- If a Plant Protection (Contingency Load Shed) scheme is installed, augmentation is required when the load at risk is at least 20% above thermal rating for more than 120hrs per year after transfers.

4.2.1.3 Meshed Melbourne CBD Subtransmission Lines and cables with Enhanced Security

ASSUMPTION: In 2008 the Essential Services Commission approved the CBD Security projects. These projects were expected to provide additional 66kV interconnections and switching to increase the level of flexibility and security of the network. This was justified due to the significance of the load and customers. For a subtransmission line outage, the network is required to be rearranged within 30 minutes so that it can withstand a second subtransmission line outage without loss of supply to customers.

APPLICATION: The zone substations that this enhanced security project affects include BQ, FR, JA, LQ, MP, VM and WA.

SPECIFIC CRITERIA FOR ENHANCED SECURITY:

For an N-1 event, the network must be reconfigured within 30 minutes to securely withstand a second subtransmission line or cable contingency event.

5 ZONE SUBSTATIONS

5.1 DEFINITIONS

5.1.1 Definition of Zone Substation

A zone substation provides the voltage transformation from the subtransmission system (normally operating at 66kV and sometimes at 22kV) to the distribution network (normally operating at 22kV, 11kV or 6.6kV). A zone substation also provides voltage regulation to maintain the distribution supply point voltage levels within the Electricity Distribution Code requirements. Zone substations are planned by the Central and Regional Planning groups.

To determine when augmentation is required there are Common Criteria applicable to all Zone Substations:

Augmentation should be considered when any of the following Common Criteria cannot be met.

- Load to be kept within 110% of station firm (N-1) cyclic rating, after taking into account all feasible distribution load transfers to adjacent stations providing the load of the other substations are also under 110% of firm (N-1) cyclic rating.
- Fault Level to be within distribution code obligations.
- Voltage to meet distribution code.

Augmentation timing is determined by station firm (N-1) cyclic rating, the capacity of distribution load transfers, customer load type (commercial, industrial or residential) and level of customer load at risk above 100% of firm capacity but not before it is justified economically.

Asset renewal due to age and/or condition is to be determined by the Asset Management group and when required, an overall review of augmentation and replacement strategies considered.

5.3.2.1 Single Transformer Zone Substation

ASSUMPTION:

For loss of the transformer the customers are interrupted before switching onto alternative supply where transfers are feasible.

If an opportunity exists to utilise the 66kV line supplying the zone substation (provided it does not impact on system security) as a 22kV feeder, then this will increase available distribution transfers.

APPLICATION:

For remote rural locations.

For loads up to 15MVA.

SPECIFIC CRITERIA FOR AUGMENTATION:

An augmentation project is identified for analysis when load exceeds 15MVA before transfers away or the normal (N) cyclic rating of the substation.

5.3.2.2 Multiple Transformer Banked Zone Substation

ASSUMPTION:

For loss of a transformer, the whole station loses supply and all customers are interrupted until the remaining transformer/s is returned to service.

APPLICATION :

(see table, red=requires upgrade)

Banked transformer zone substations are applicable for customer loads up to 15-20MVA in predominately rural areas and consideration will be given to conversion to partial or fully switched when major augmentation is carried out to achieve station operability and economically enhance reliability.

Existing banked substations with sufficient capacity may exceed the above load criteria until major augmentation is required.

Suitable for radial subtransmission lines with load under 20MVA.

N-1 – Fully Switched, >15MVA Urban			N-1 – Fully Switched, >20MVA rural		Banked <20MVA Rural	Banked <15MVA, Rural
AC	AL	BAN	CME	CMN	ART	COB
BMH	CLC	CRO	CTN	HTN	CDN	NHL
DDL	BAS	BGO	KRT	MBN	CHA	OYN
ECA	EHK	FNS	MRO	NKA	WMN	WIN
GB	GCY	GL	PLD	RVL	CHM	
GLE	HSM	KYM	SHP	STL		
LV	LVN	MDA	TRG	BBD		
MLN	MNA	SA	GSB			
SHL	SHN	SSE				
STN	WBE	WBL				
WND	WPD	DLF				
SU						

SPECIFIC CRITERIA FOR AUGMENTATION:

An augmentation project is identified for analysis when load at risk is greater than 10% of station firm N-1 cyclic rating for more than 120 hours per year after transfers away.

5.3.2.3 Multiple Transformer Switched Zone Substation

ASSUMPTION: For loss of a transformer, the whole load transfers to the remaining transformer/s. No interruption to customers unless a contingency load shedding scheme is in place.

APPLICATION: Switched zone substations are applicable for loads in excess of 15MVA unless the subtransmission supply is radial and 66kV circuit breakers are not required to switch larger sized transformers.

SPECIFIC CRITERIA FOR AUGMENTATION:

An augmentation project is identified when:

- The forecast load exceeds the station firm cyclic rating and the excess load is unable to be transferred away automatically.
- If an automated load transfer scheme is installed, the station can be loaded above firm cyclic rating by the amount of automatic transfers available.
- Installation of a plant protection scheme may be considered where a major augmentation cannot be economically justified.
- If a Plant Protection (Contingency Load Shed) scheme is installed, augmentation is required when the load at risk is at least 10% above firm cyclic rating for more than 120hrs per year after transfers away, as per Multiple Banked Zone Substations.

5.3.2.4 Powercor & CitiPower Future Zone Substation Upgrades

Conversion of Multiple Transformer Zone Substations from Banked to Fully Switched

In order to align with best practice related to security of supply and reliability, multiple transformer banked zone substations will be considered for conversion to fully switched when other major upgrade work is being undertaken. The decision to convert to fully switched will involve an economic analysis of the improved reliability against the differential cost to include the work in the major upgrade.

Installation of Plant Protection Schemes

When load is to exceed 110% of firm N-1 cyclic rating for fully switched zone substations or 120% of the thermal rating for looped subtransmission lines under the loss of one looped line, consideration should be given to installing a plant protection (or load shed scheme) to prevent plant damage for loads in excess of the N-1 cyclic rating or line thermal rating.

Subtransmission Line Circuit Breakers:

When a looped overhead subtransmission line is more than approximately 10km in length, line circuit breakers should be considered for installation at each zone substation end. An economic justification considering line outage risks will be required for the installation of line circuit breakers.

5.3.3 Zone Substation Fault Level Mitigation Strategies

Normally Open Auto Close Schemes:

When zone substation low tension 6.6kV, 11kV or 22kV bus fault levels are forecast to exceed code limits, consideration should be given to opening a transformer circuit breaker and the installation of an auto close scheme to enable fault levels to be reduced. The substation maximum capacity will then be the N cyclic rating of the transformers supplying the load.

When forecast load exceeds the N cyclic rating of the transformers supplying the load, a low tension bus tie circuit breaker should be opened instead and a bus tie auto close scheme installed to carry the load following a momentary outage. Separate voltage regulating relays will be required also to regulate the separated bus voltages independently. A plant protection (load shed) scheme may also be required to prevent overloading following an auto close operation.

Voltage impacts are to be considered in the evaluation of this type of scheme. Refer to the Victorian Electricity Distribution Code (clause 4.8) for the Australian/New Zealand Standards references on allowable disturbance limits.

5.3.4 Embedded Generation

Contributions over 1MW at times of peak demand from embedded generation connected to the distribution network are considered as not generating for the purposes of load forecasts.

Connected generation can also be considered to defer augmentation where there is a Distribution Network Support Agreement in place. Non-Network solutions including Demand Side Response and/or embedded generation can be an effective means to defer augmentation provided reliability is ensured at peak load times.

6 HIGH VOLTAGE DISTRIBUTION NETWORK

6.1 DEFINITIONS

6.1.1 Definition of a High Voltage Distribution Network.

A High Voltage (HV) Distribution network starts at a terminal station or zone substation low voltage busbar and end at the HV transformer connection in a distribution substation. A HV distribution network comprises of electric lines and cables at nominal voltages of 22kV, 12.7kV, 11kV or 6.6kV which the Distribution Businesses (also called Distribution Network Service Providers) own and operate to distribute electricity to customers under their Distribution Licence. It is a subset of a Distribution Network.

6.2 PLANNING CRITERIA FOR AUGMENTATION

6.2.1 Radial Distribution lines (Rural Long & Rural Short)

Radial Rural Long and Rural Short HV distribution lines are defined as feeders with a specific line length and for the purpose of planning guidelines where only limited load can be transferred to adjacent feeders.

ASSUMPTIONS: Planned and unplanned outage of the line will result in a supply interruption to customers.

APPLICATION

Rural locations or supply to a single customer.

For Rural Short feeders with a total length of less than 200 km.

For Rural Long feeders with a total length of greater than 200 km.

The maximum thermal rating of a line is to be 65ºC for normal capacity lines and higher at 80ºC for high capacity lines as per CitiPower Powercor Conductor Rating Standards provided no other system limitation applies.

SPECIFIC CRITERIA FOR AUGMENTATION:

An augmentation project is initiated when:

- The actual or forecast load exceeds or equals the summer or winter thermal rating of the feeder.
- Voltage cannot be kept within the Distribution Code specifications.
- The actual or forecast load exceeds the rating of protecting devices (e.g. rating of an ACR only 100 amps and need to augment fuses downstream of the ACR due to load growth).
- Operating temperature of plant is above its rating (e.g. top oil temperature of regulators to 100°C).

As a guideline, the average customer numbers on a feeder should not exceed 4,000 customers.

6.2.2 Looped Distribution lines (Rural Long)

Looped Rural Long HV distribution lines are defined as feeders where some load can be transferred to adjacent feeders, although they are normally operated with open tie points i.e. radially.

ASSUMPTIONS: Planned and unplanned outage of the line will result in supply interruption to all customers downstream of the CB or ACR until some of the load is transferred to an adjacent feeder.

The maximum thermal rating of a line is to be 65ºC for normal capacity lines and higher at 80ºC for high capacity lines as per CitiPower Powercor Conductor Rating Standards provided no other system limitation applies.

APPLICATION:

Remote rural locations where there are two or more feeders to supply the load but it is not economical or practical to build in full backup.

For Rural Long feeders with a total length of greater than 200 km.

SPECIFIC CRITERIA FOR AUGMENTATION:

An augmentation project is initiated when the:

- Feeder load maximum demand is greater than or equal to 80% of thermal rating of the line.
- Voltage cannot be kept within the Distribution Code specifications.
- Load has exceeded rating of protecting devices (e.g. rating of an ACR only 100 amps and need to augment fuses to ACR due to load growth).
- When operating temperature of plant is above its rating (e.g. top oil temperature of regulators to 100°C).

As a guideline, the average customer numbers on a feeder should not exceed 4,000 customers.

6.2.3 Looped Distribution Lines (Urban & Rural Short)

Looped Urban and Rural Short HV distribution lines are defined as feeders where all load can be transferred to adjacent feeders, although they are normally operated with open tie points i.e. radially.

ASSUMPTIONS:

Planned and unplanned outage of one line in the loop arrangement does not necessarily result in a sustained supply interruption to customers. The load of one line can be transferred to adjacent two feeders.

The maximum thermal rating of a line is to be 65ºC for normal capacity lines and higher at 80ºC for high capacity lines as per CitiPower Powercor Conductor Rating Standards provided no other system limitation applies.

APPLICATION:

For feeders with a load density of greater than 0.3MVA per km (Urban).

For feeders with a total length of less than 200 km (Rural Short) and there are available transfers.

In urban areas, all feeders (subject to cable and conductor rating limitations) can be loaded to the normal planning load limit and it is not usual practice to plan for unloaded standby or backup feeders.

The planning of feeder loadings shall consider the contribution (under abnormal conditions) of any HV fault initiated auto-changeover systems that may be installed.

Inter-feeder tie lines from the same zone substation should be provided approximately halfway along the load-measured length, and towards the end of the feeder. The switches in these ties must be normally open and shall be 3 phase gang operated and either manual or if economically justified, remotely controlled.

Tie lines should be provided between feeders of adjoining zone substations to maximise load transfers away where practical and economic.

Consideration shall also be given to the provision of ties to adjacent feeders in terms of ½ and 1/3 feeder customer numbers for the purpose of future installation of remote operable or automated restoration schemes.

Adjacent feeders should preferably originate from different zone substation buses, unless the bus tie CB is normally operated open.

<u>SPECIFIC CRITERIA FOR AUGMENTATION</u>:

An augmentation project is considered when the:

- Forecast load exceeds the summer or winter thermal rating of the adjacent two lines when one of the lines in the looped system is out of service (first order contingency).
- Feeder load maximum demand is greater than 67% of thermal rating of line.
- Voltage cannot be kept within the Distribution Code specifications.
- Load has exceeded rating of protecting devices (e.g. rating of an ACR only 100 amps and need to augment fuses to ACR due to load growth).
- Operating temperature of plant is above its rating (e.g. top oil temperature of regulators to 100°C).

As a guideline the average customer numbers on a feeder should not exceed 4,000 customers on the PAL distribution network and 2500 customers on the CP distribution network where there is a standard capacity network or 4,000 customers if there is a high capacity HV network.

6.2.4 CitiPower CBD Distribution

The CitiPower CBD system generally operates as a (radial) feeder group arrangement. Between two and eight feeders constitute a feeder group. One stand-by feeder is provided for each group to enable the full load from a faulted feeder to be manually transferred to the group's stand-by feeder.

ASSUMPTIONS:

The stand-by feeder operates without load until there is an outage of an adjacent feeder in the group upon which it will be placed into service to carry the load of the faulted feeder.

No load shall be connected to the stand-by feeder without prior authorisation of the Network Planning group.

Feeders within the groups emanate from different buses at the zone substation and normally end at an open point at a remote switching station. In the initial stage, feeders will run between two zone substations with the open point at one end and as load grows a strategy will be investigated to develop a switching station to take its place at some central location between the two zone substations. This allows for capacity of the feeders to be effectively doubled by creating two feeders from one.

APPLICATION:

All feeders within the Melbourne CBD (former Melbourne City Council Electricity Supply – MCCES) area are planned in this way.

SPECIFIC CRITERIA FOR AUGMENTATION:

An augmentation project is initiated when the actual or forecast load of any feeder in the group except the standby, equals or exceeds 100% of the thermal rating of the feeder.

6.2.5 SWER System

The Single Wire Earth Return (SWER) network is supplied from typically long 22kV feeders through isolating transformers converting to 12.7kV.

ASSUMPTIONS:

Due to the remote location the SWER system operates as a radial network where load cannot be transferred to any other adjacent feeders.

Planned and unplanned outage of the line will result in a supply interruption to customers.

APPLICATION:

SWER networks are part of the distribution system supplying remote customers that are a significant distance from the main 22kV distribution infrastructure. SWER is a low cost system that has been established in the rural parts of Victoria and has many limitations e.g. very low capacity and fault levels.

SPECIFIC CRITERIA FOR AUGMENTATION:

An augmentation project is considered when the:

- Load is greater than 125% of nameplate rating of a 100kVA SWER isolating transformer i.e. 125kVA.

- Voltage cannot be maintained within the Electricity Distribution Code requirements.
- Protection is compromised by high load of Isolating transformers.
- Step and touch potential (earth voltage rise) exceeds acceptable levels in public access areas.
- Maximum earth return current to be 125% of nameplate rating to prevent compromising earth impedance integrity due to overheating.

6.3 CMEN

The Common Multiple Earth Neutral (CMEN) system is to be installed where step and touch potentials in public access areas exceeds 'The Code of Practice for the Protection of Personnel and Equipment against Earth Potential Rises Caused by High Voltage Power System Faults' requirements. The CMEN system has been instigated due to the introduction of lines being constructed with concrete poles (conductive poles).

Progressive conversion to CMEN is policy in urban areas to enable closer proximity to Telstra assets.

6.4 HIGH VOLTAGE AUGMENTATION

The HV Augmentation Planning Policy and Guidelines (document No. 15-20-CP0001) contains detailed planning guidelines in relation to feeder capacity and loadings, conductor and cable sizes, switching arrangements, automation and substation interconnections.

The Commercial & Industrial Supply Projects Guideline (document No. 04-30-G0005) covers detailed system augmentation requirements in specific detail for the connection of new HV or LV customer supply projects.

7 LOW VOLTAGE AUGMENTATION

7.1 DEFINITIONS

7.1.1 Definition of a Low Voltage Distribution Network

A Low Voltage Distribution Network comprises of a network of distribution substations transforming voltage from a nominal 6.6kV, 11kV or 22kV to 230/400/460V and overhead and underground lines at nominal voltages of 230/400/460V, which the Electricity Networks are licensed to use to distribute electricity for supply under their Distribution Licence.

The augmentation planning of these assets is done by Network Services for:

- Supply Quality group for overloaded or out of Distribution Code substations and LV lines.
- Customer Projects groups for new customer load.

The LV Augmentation Planning Policy & Guidelines (document No. 01-10-CP0001) covers augmentation threshold requirements.

8 ECONOMIC ANALYSIS

The correct time to carry out an augmentation project from an economic perspective is when the annualised cost of capital is less than the reduction in value of ‘expected unserved energy’ and ‘energy not supplied’ brought about by the project.

Operational distribution transfers between zone substations to alleviate load at risk or load above N are not taken into account when carrying out an economic assessment of expected unserved energy. Operational transfers may be used to determine the relative merits of two projects for budget purposes and can be used to alleviate load at risk until augmentation occurs however.

8.1 VALUE OF ‘EXPECTED UNSERVED ENERGY’ ‘N-1’

The value of expected unserved energy is determined from the Value of Customer Reliability in $/MWh (published by AEMO) for the appropriate customer type multiplied by the expected unserved energy in MWhr under N-1 conditions.

70% of the 50% PoE and 30% of the 10% PoE expected unserved energy is used in the above calculation. A combination of 10% and 50% PoE energy at risk is used to fully evaluate the impact of an outage. The weighting of 70% and 30% are similar to what AEMO uses to evaluate energy at risk and provides an avenue to account for 10% energy at risk.

The expected unserved energy in MWhr is estimated by multiplying the energy at risk under N-1 conditions in MVAh by the load powerfactor and the probability of the contingency event occurring for the average time of such contingency outages.

The energy at risk in MVAh is estimated by scaling a normalised annual load duration curve to the forecast load in MVA and determining the difference (being energy at risk) between the N-1 rating and the forecast load. The zone substation load duration curve is used for a subtransmission line with the latter rating corrected for losses.

The probability of a transformer outage in a year is the number of transformers multiplied by the probability of failure (usually assumed to be 1% per annum unless specific information is available) multiplied by 2.6 months mean outage time and divided by 12 months.

The probability of a line outage is the line length in km multiplied by the outage rate per km by the outage time and divided by the number of hours in a year. Outage times range from typically 8 hours for overhead lines, 72 hours (3 days) for HV underground cable and up to 168 hours (1 week) for 66kV underground cables.

Typical failure rates for lines are 1 fault per 100km per annum for subtransmission overhead lines. Outages for line maintenance should also be taken into account. This can vary from 1 outage per 100km per annum to up to 5 outages per 100km per annum depending on the age of the asset.

8.2 VALUE OF 'ENERGY NOT SUPPLIED' 'N'

The value of energy not supplied when all plant is in service (that us, under 'N' condition) is determined from the Value of Customer Reliability in $/MWh (published by AEMO) for different customer types multiplied by the estimated energy not supplied in MWh.

70% of the 50% PoE and 30% of the 10% PoE energy not supplied is used in the above calculation.

The energy not supplied in MWh is estimated by multiplying the energy not supplied above N capacity in MVAh by the load powerfactor and a probability of one.

The energy not supplied in MVAh is estimated by scaling a normalised annual load duration curve to the forecast load in MVA and determining the difference (being the energy not supplied) between the N rating and the forecast load.

8.3 TOTAL VALUE OF ENERGY AT RISK

The total value of 'expected unserved energy' and 'energy not supplied' is derived by summing the two values from sections 5.1 & 5.2 above.

8.4 OPTION ANALYSIS

In order to evaluate various projects on an economic basis to determine which project is best and to confirm the timing of that project, it is necessary to consider the following:

The best project to solve an augmentation issue is the project with the maximum positive net present benefits over a range of economic scenarios. Instead of choosing the least cost project, this approach chooses the project that maximises benefits to consumers.

Typically, the benefits are the reduction in the value of energy at risk by carrying out the project, less the cost involved. Other classes of market benefits, changes in energy losses and additional option values as per the RIT-D in 5.17 of the NER and in the RIT-D application guidelines can also be included. This approach is similar to timing a project on the basis of annualised costs being less than annualised risk, except that with different options and costs there will be varying emerging risk in later years and an economic analysis of these costs and benefits can be used to determine which project provides the maximum net present benefits over the long term.

Costs are usually determined from the capital cost for augmentation with an allowance for ongoing annual operational expenditure.

The range of economic scenarios can include lower load growth and higher and lower capital, operational costs and varying finance discount rates and the value of customer reliability.

Confirmation of economic timing for a project can be demonstrated when project deferral reduces net benefits.

The project benefits can also be used to compare the relative merits of different projects if other factors such as transfers, code compliance, Health and Safety etc. are taken into account.

8.5 LOAD DURATION CURVE

This is a graph of actual load in MVA verses duration in hours for a year for a particular asset. The load is on the Y axis and duration is on the x axis with load ordered on an hourly interval basis independent of when the load occurred during the year from highest load at minimum time to lowest load at maximum time. This curve demonstrates the amount of time or duration that a certain load exists on a particular asset.

Load in MVA is used for the Load Duration Curve (LDC) to compare directly with plant ratings that are usually given in MVA or Amps which can be converted to MVA. Integration of the load at risk will produce energy at risk. Economic studies can be based on MVA & corresponding energy at risk and can include other plant such as capacitor banks as well as additional transformers in options.

The same LDC can be used for 50% PoE and 10% PoE energy at risk analysis. The LDC is based on up to five years of available interval load data. The individual LDC yearly data is normalised before averaging with other years to form a composite curve.

Appendix A - Glossary

Annual Load Duration Curve: This is a Load Duration Curve for a particular loaded asset for a year with a base of as close as possible to 8,760 hours.

Annualised Cost of Capital: This is defined by a simple annuity formula that is the fixed payment required at a defined interest rate (at present 8% is a typical amount used) to service the capital cost of the augmentation required to alleviate the load at risk.

Assets: Physical materials e.g. poles, lines, cables, transformers, circuit breakers etc that make up the system or network.

Augmentation: Upgrading to provide a higher capacity by various means including allowing to operate conductors at higher temperatures whilst maintaining safe clearances (raise conductors, resurvey, use existing spare height), replacement with larger unit etc.

Cable: Underground cable capable of supplying load.

CBD: Refers to the 'Central Business District of Melbourne' sometimes also referred to as the 'Central Activities District of Melbourne' and from a planning policy perspective covers the former Melbourne City Council Electricity Supply (MCCES) area.

Format: Meaning an arrangement of the type of asset in the table in section 3.2.

Conductor: Technically a path for electricity however mainly used in this guideline as an overhead line conductor capable of supplying load.

Connection Assets: These are assets that Distribution Businesses are supplied from and connect to at a Terminal Station. These assets are owned by the Transmission Network Service Provider (TNSP) and, in Victoria, are planned by the Distribution Businesses that are connected. These assets generally connect to 'shared' 220kV and above assets for the purpose of supplying 66kV Distribution Business load and comprise of 220kV circuit breakers, 220/66kV transformers and 66kV busses, circuit breakers and capacitor banks. In some cases where 11kV or 22kV supplies exist at terminal stations, connection assets also include 220/22kV or 220/66/22kV transformers and 22kV busses, circuit breakers and capacitor banks. Note that AEMO will determine if 220kV assets such as circuit breakers and bus extensions that are required for a connection asset augmentation are to be classified as 'shared' or 'connection assets' for the purposes of AEMO involvement in the project and the Regulation Investment Test type. Also, in general, the 22kV distribution feeder circuit breakers which directly supply customers and transfer busses at terminal stations are owned by Distribution Businesses. However any 22kV subtransmission circuit breakers at terminal stations are considered connection assets.

Contingency Event: This is a single event affecting the power system or network which involves the failure or removal from service of one or more subtransmission or distribution lines or zone substation transformers. The usual application of this definition involves the loss of one line or transformer or in the case of direct connected line to transformer combinations, the loss of both line and transformer for a single contingency event.

Contingency Planning: This is used to reduce the unserved energy following a single contingency event that cannot be supplied by existing immediately located assets remaining on supply. It can involve multiple transfers away, spare plant, and mobile generation, special plant switching arrangements, portable fans and other initiatives to keep as many customers on supply as possible.

Credible Contingency Event: This is a single event affecting the power system or network which involves the unexpected failure or removal from service of one or more subtransmission or distribution lines or zone substation transformers. The usual application of this definition involves the loss of one line or transformer or in the case of direct connected line to transformer combinations, the loss of both line and transformer for a single contingency event. This definition is similar to that contained in the National Electricity Rules and has been simplified for the purpose of this guideline policy document.

Criteria: The trigger or point at which augmentation is required.

Customer Interruption Time: This is the time that customers are expected to be without supply whilst arrangements are being made to restore supply.

- <1 Minute: This restoration time is applicable for fully switched zone substations with automatic protection and control schemes that isolate faulty system elements and could also switch in reserve capacity to maintain supply.

- < 4 Hours: This response time is applicable for banked zone substations and is due to the need to manually determine the fault, isolate it and restore supply. This process can typically take up to 4 hours depending on the location of the faulted asset, the type of fault and resource availability.

- Best Practice: This response time is applicable for single transformer stations and radial lines in rural areas due to the best practice that can be achieved given resource availability, travel distance and fault type.

Cyclic: Daily load profile or cycle.

Cyclic Rating: This is the allowable cyclic load under particular operating temperatures, environmental conditions and load profile.

Deterministic: Means that augmentation is triggered by a set of criteria that is event based. The risk or probability of the event occurring is not taken into account.

Distribution: As distinct from Subtransmission, these are Distribution Assets that are supplied from zone substations and usually operate at High Voltage (HV): 22kV, 12.7kV, 11kV and 6.6kV and Low Voltage (LV): 430 and 415V.

Distribution Annual Planning Report (DAPR): This is a 5 year forward review of the forecast loads and capability of the distribution network to meet predicted demands detailing proposed augmentation works for the subtransmission system. The proposed augmentation works result from application of these Network Augmentation Planning Policy & Guidelines.

Distribution Area: This is a defined area that contains the assets of a Distribution Business.

Distribution Assets: These are assets of Distribution Businesses used to supply electricity.

Distribution Business (DB): The business that owns the assets exiting a terminal station that makes up a network to supply customers and holds the Licence to distribute electricity in that area. Also known as a Distribution Network Service Provider (DNSP).

Distribution High Voltage Line/Feeder Reliability Categories:

- CBD Feeder: A feeder supplying predominately commercial or high-rise buildings, underground and containing significant interconnection and redundancy when compared to urban areas.

- Urban Feeder: A feeder, which is not a CBD feeder, with load density greater than 0.3MVA/km.

- Rural Short Feeder: A feeder which is not a CBD or Urban feeder with total length less than 200 km.

- Rural Long Feeder: A feeder which is not a CBD or Urban feeder with total length greater than 200 km.

Distribution Licence: Licenses the Licensee to distribute electricity for supply, and to supply electricity, in the distribution area and using the distribution fixed assets, subject to the conditions set out in the licence.

Distribution Load Transfers: These are HV feeder loads that can be transferred from a zone substation to adjacent zone substations in the event of a plant outage. Adjacent zone substation/s can be loaded to their N cyclic rating if “Banked” or “Switched” with a load management scheme. If the switched zone substation doesn’t have a load management scheme it can only be loaded to its firm (N-1) cyclic rating. Tie feeders can be loaded to their maximum thermal rating.

Distribution Network: This is defined in the NER as a network not being a transmission network. A Distribution Network contains subtransmission lines, zone substations, HV feeders, distribution substations and LV lines.

Distribution System: This is as defined in the NER as consisting of a Distribution Network and Connection Assets.

Dynamic Line Monitoring: Environmental data such as wind speed and ambient temperature is used to produce a real time thermal rating for an overhead line.

Energy-at-Risk: the total energy at risk over a period of time (typically a year, expressed in MWh), which is the summation of load above the applicable rating for a defined N-1 scenario. This quantity is specified by both the ‘Maximum Load as % of Rating’ and the ‘Maximum Time over Rating, Hours’ in the table in Section 3.2.

Energy Not Supplied: This is the total energy that is unable to be supplied over a period of time (typically a year and expressed in MWh) when load exceeds ‘N’ capacity on a line or plant item.

Feeder: Can be a subtransmission or distribution line supply load.

Firm Cyclic Rating: This is the cyclic rating of the station or line after an N-1 contingency event.

Guideline: Direction on the policy.

Limited Cyclic (Emergency) Rating: This is a special duty rating applied to overhead conductor lines.

Line: This is a circuit or feeder carrying load. It generally refers to both overhead conductors and underground cable unless specified as overhead line or cable.

Load-at Risk: The instantaneous load above the applicable rating for a single point in time, to the ‘Maximum Load as % of Rating’ or ‘Maximum Time Over Rating, Hours’ in the table in Section 3.2.

Load Control Scheme: This is an automatic control scheme to enable higher system loads to be carried on plant without risk of damage from overload.

Load Duration Curve: This is a graph of actual load in MVA verses duration in hours for a year for a particular asset. See section 5.5 above. See also Annual Load Duration Curve and Normalised Annual Load Duration Curve.

Load Magnitude: This is the guideline load for a particular type and class of asset.

Maximum Demand: For measured demands, this is the maximum actual load as detected on an asset at intervals of 15 minutes for high voltage feeders and zone substations. For subtransmission and connection assets, 30 minute data is commonly used by AEMO for the assessment of maximum demands.

Maximum Load as a % of Rating: The maximum load depends on a number of factors and is mainly determined by conductor and plant type, size and rating, transfers away and load and hours at risk. The maximum load figures given in the table in section 3.2 are a guide and there are other detailed planning criteria to be also taken into account that specify the actual augmentation triggers e.g. in the case of a banked zone substation, the specific criteria for augmentation is when both the load at risk is greater than 10% above N-1 cyclic rating after transfers away and the load at risk exists for at least 120hrs above N-1 cyclic rating after transfers away.

Maximum Time Over Rating: This is the maximum accumulated time that load can exceed plant rating in a year, before augmentation is considered.

Multiple Transformer Banked Zone Substation: This describes a zone substation with multiple transformers in a single switched group. A single transformer fault will result in the loss of all transformers and consequently all feeders and customers at that substation.

Multiple Transformer Switched Zone Substation: This describes a zone substation with multiple transformers having circuit breakers on all connection paths between each transformer and the 11kV or 22kV bus. A single transformer fault will automatically isolate the faulty transformer keeping the remaining transformers and all feeders on supply.

Network: The physical assets of a business used for the delivery and conversion of electrical energy to customers. The word is interchangeable with ‘System’.

N: This refers to the system being in its normal state.

N-1: This refers to system normal minus one element (transformer, line etc) i.e. being subjected to a single credible contingency event.

N-1 Cyclic Rating: See Firm Cyclic Rating.

N-1 Partial: This refers to system normal minus one element i.e. being subjected to a single credible contingency event and not all load is feasible to be secured by transfers.

N-2: This refers to system normal minus two elements i.e. being subjected to two credible contingency events.

National Electricity Rules (NER): Specifies the rules by which the National Electricity system operates.

Network Asset Management Plan: This plan contains the strategic direction for maintaining assets at defined capacity and reliability service levels. It involves policy on when assets are to be replaced or maintained but not augmented.

Normal Cyclic Rating: This is the cyclic rating of the station or line under normal or N conditions.

Normalised Annual Load Duration Curve: This is an annual load duration curve that has the actual load values divided by the maximum demand for that period.

Overhead Line Continuous Rating: This is the maximum continuous load that an overhead line conductor can carry without exceeding its thermal design limit.

Overhead Line Limited Cyclic Rating: This is the maximum emergency load that an overhead line conductor can carry for a specified limited time period without exceeding its thermal design limit. It is usually applicable for limited use of 2-3 times per year.

Peak Load Days: These are days where the load is defined as 50% PoE or above (i.e. 10% PoE). PoE refers to Probability of Exceedence.

Plant Protection Scheme: Applied to Zone Substations and subtransmission looped lines and also known as a Load Shed Scheme whereby transformer and or subtransmission line load and circuit breaker status is continually monitored and if a contingency event occurs with load on remaining in service transformer and lines, load will be shed in a controlled manner to maintain load within ratings on remaining in-service plant and lines. This preserves transformer and lines from potential damage from sustained system overload. Terminal Stations use a similar scheme to prevent overload damage and operates under system normal N or N-1.

PoE: See Probability of Exceedence.

Policy: Describes the course of action for the augmentation of the network.

Powercor CitiPower Company Vision:

“Connecting for a Bright Future”

The key themes that sit behind this statement include:

- *we want to help to create a bright future for our shareholders, our employees, our customers and the communities which we service*
- *the services we provide are a critical enabler of a future where people are increasingly more connected and can access evolving technologies*
- *we will continue to provide regulated “poles and wires” electricity distribution services, but in an environment where our customers will have a voice in the regulatory decision-making process and desire increased flexibility regarding our services and the technology we utilise to deliver them.*

Probability of Exceedence: This is the probability that a load will exceed a certain value. Forecasts are prepared on a 50% PoE basis i.e. The 50% PoE demand forecast relates to maximum demand corresponding to an average maximum temperature that will be exceeded, on average once every two years. Similarly, the 10% PoE demand forecast relates to maximum demand corresponding to an extreme maximum temperature that will be exceeded, on average once every ten years.

Rating: This is the allowable load for a transformer, cable, line or other distribution plant item. Typical transformers ratings are expressed as nameplate, cyclic, and emergency cyclic. Typical cable ratings are expressed as continuous, cyclic and emergency cyclic. Typical overhead line ratings are expressed as continuous and limited cyclic (emergency). Zone substations can have an N Cyclic rating and a Firm or N-1 Cyclic rating.

Regulation Investment Test – Distribution (RIT-D) or Transmission (RIT-T): This is a cost-benefit test that Network Service Providers must apply when assessing the economic efficiency of different investment options. The best option will be shown in the test to have provided the maximum net positive market benefits.

Rural: Generally refers to developed areas of towns and countryside surrounding. Separate definition to Rural Short and Rural Long distribution feeders.

Security Standard: Defines the level of security of supply i.e. N means there is no backup supply available. N-1 means that for the contingency condition of the loss of one element, there is backup supply available.

Shared Transmission Assets: These are assets at a terminal station and transmission line level that are used to support the overall transmission system and hence are 'shared' across all major users. These assets are typically busses, circuit breakers and transmission lines at 220kV, 330kV and 500kV.

Short Time Emergency Cyclic Rating: This is a special defined time overload rating for underground cables. It usually follows a period of normal load then a much higher overload for the defined period of time, then followed by a reduced load period well within normal cyclic ratings. The maximum defined period overload is determined from thermal modelling.

Substation: A facility where the conversion or transformation of electricity from a higher voltage to a lower voltage takes place.

Subtransmission: These are Distribution Business assets that exit Terminal stations for the supply of zone substations and usually 66kV but can include 22kV for older systems. They include zone substations.

The Electricity Distribution Code (EDC): The purpose of this code, applicable in Victoria, is to regulate the following activities so that they are undertaken in a safe, efficient and reliable manner:

- The distribution of electricity by a distributor for supply to its customers;
- The connection of a customer's electrical installation to the distribution system;
- The connection of embedded generating units to the distribution system; and
- The transfer of electricity between distribution systems.

The Electricity System Code (ESC): The purpose of this code, applicable in Victoria, is to regulate the following activities so that they are undertaken in a safe, efficient and reliable manner:

- The provision of shared transmission network services by transmitters;
- The connection of distributors and EHV consumers to the transmission network;
- The connection of generating Units to the transmission network; and

- The transfer of electricity between transmission networks.

Terminal Station: A facility where the conversion or transformation of electricity from a higher transmission voltage to a lower subtransmission or distribution voltage takes place.

Thermal Rating: This is the current rating possible for a given maximum operating temperature and a set of standard predefined environmental conditions comprising of wind speed, solar radiation etc and material limitations. See Thermal Line Limits and Thermal Cable Limits for more information.

Thermal Line Limits: This is the maximum operating temperature of the line that can be achieved and maintain all clearances to adjacent conductors, phase to phase separation, ground clearance, circuit to circuit clearance and also within annealing limits of the conductor.

Thermal Cable Limits: These are limits applied to underground cable conductor temperature due to cable insulation capabilities. The most commonly used cable insulation type, XLPE is limited to a maximum temperature of 90ºC. Other cable insulation types have different maximum operating temperatures.

Transfers: Refer to Distribution Load Transfers.

Transfers Away: Refer to Distribution Load Transfers.

Transformer Cyclic Rating: This is the cyclic load a transformer can carry without exceeding 130ºC hot spot winding temperature for a specified 'Loss of Life' of 12pu per day. This rating allows for transformer operation at the cyclic rating load level for up to a 6 months' time period to cover the removal for repair of one transformer from a group under a N-1 contingency event.

Transmission Network: A network of assets operating at nominal voltages of 220kV and above or of voltages between 66kV and 220kV that support the higher voltage transmission network.

Transmission Connection Planning Report (TCPR): This is a 10 year forward review of forecast loads and capability of terminal stations to meet predicted demands detailing proposed augmentation works and options.

Underground Cable Continuous Rating: This is the maximum continuous (flat) load that an underground cable can carry without exceeding its thermal rating.

Underground Cable Cyclic Rating: This is the maximum cyclic load that an underground cable can carry without exceeding its thermal rating.

Underground Cable Short Time Emergency Cyclic Rating: This is the maximum cyclic load that an underground cable can conduct for a short time without exceeding its thermal rating. The short time is usually less than 24 hours.

Urban: Refers to developed areas of major city and regional centres excluding Melbourne CBD. Separate definition to Urban distribution feeders.

VCR: Refers to the Value of Customer Reliability. This is the value consumers place on having a reliable supply of electricity, and is equivalent to the cost to the consumer of having that supply interrupted for a short time. VCR is expressed in $/MWhr.

Appendix B – Code and NER Related Planning Criteria

The information presented in this appendix is generally sourced from the Electricity Distribution Code and the National Electricity Rules and is reproduced here with some modification to enable planning of the network to be done within various requirements. Refer to the EDC, NER and relevant Australian Standards for further detailed information.

<u>Fault Levels</u>:

Refer to Section 7.8 of The Electricity Distribution Code where table 5 specifies the maximum fault levels that an embedded generator must not cause to exceed and align with the pre 2001 current levels below. All work should be done to restrict fault levels to these figures until sufficient new installations have occurred to enable a system wide fault level increase.

The table below specifies the new Powercor/CitiPower zone substation plant ratings (circuit breakers etc) to ensure coverage over and above EDC requirements.

		Existing Installation (Pre-2001)		New CP/PAL Installation/Designs (Post 2001)
	Voltage Level	Short Circuit Level	Current	Current (Duration)
Sub-transmission System	66kV	2500 MVA	21.9 kA	31.5kA (2s)
	22kV	1000 MVA	26.2 kA	31.5kA (3s)
Primary Distribution System	22kV	500 MVA	13.1 kA	20kA (3s)
	11kV	350 MVA	18.4 kA	25kA (3s)
	6.6kV	250 MVA	21.9 kA	25kA (3s)

The table below shows typical transformer impedances to enable fault levels on the existing network to be managed.

Transformer Purpose	Voltage Transformation	Impedance
Terminal Station 150 MVA Transformers	220/66 kV	15% on 150MVA at nominal tap
Terminal Station 225 MVA Transformers	220/66 kV	30% on 225MVA at nominal tap
Zone Substation Transformers (Urban & Rural)	66/22 kV	9.3% on 20MVA at nominal tap
Zone Substation Transformers (Urban Areas)	66/11-6.6 kV	13.5% - 14.25% on 20MVA at nominal tap
Zone Substation Transformers (CBD Areas)	66/11 kV	25.5% on 55MVA at nominal tap
Zone Substation Transformers (Urban & CBD Areas)	22/11-6.6kV	10% on 10MVA at nominal tap

Harmonics:

Refer to Section 4.4.1 of the Electricity Distribution Code. The table below shows voltage harmonic levels that a distributor must ensure is kept at the point of common coupling nearest to the customer's point of supply:

VOLTAGE HARMONIC DISTORTION LIMITS			
Voltage at point of common coupling	**Total harmonic distortion**	**Individual voltage harmonics**	
		Odd	**Even**
<1kV	5%	4%	2%
>1kV and <=66kV	3%	2%	1%

Refer to Section 4.4.3 of the Electricity Distribution Code for Current Harmonic limits for customers.

Refer to NER System Standards S5.1a.6 Voltage waveform Distortion, where harmonic voltage distortion level of supply should be less than the 'compatibility levels' defined in Table 1 of Australian Standard AS/NZS 61000.3.6:2001. To facilitate the application of this standard Network Service Providers must establish 'planning levels' for their networks as provided for in the Australian Standard.

Refer to AS61000-3-6:2001 Table 2 Indicative Planning Levels for Harmonic Voltages. AEMO will allocate a proportion of the planning levels based on the distribution business load share of terminal station capacity. This will be less than the table below and significantly less than the Distribution Code levels. CitiPower/Powercor must allocate a sub portion of this allocation for individual large customers and generators.

Odd Harmonics (non-multiple of 3)		**Odd Harmonics (multiple of 3)**		**Even Harmonics**	
Order h	**66-220 kV Harmonic Voltage Limit (%)**	**Order h**	**66-220 kV Harmonic Voltage Limit (%)**	**Order h**	**66-220 kV Harmonic Voltage Limit (%)**
5	2.0	**3**	2.0	**2**	1.5
7	2.0	**9**	1.0	**4**	1.0
11	1.5	**15**	0.3	**6**	0.5
13	1.5	**21**	0.2	**8**	0.4
17	1.0	**>21**	0.2	**10**	0.4
19	1.0			**12**	0.2
23	0.7			**>12**	0.2
25	0.7				
>25	0.2 + 0.5 (25/h)				
Total harmonic voltage distortion contribution at 66-220 kV: 3% Non-integer harmonic voltage contribution: 0.2%					

Voltage Limits:

Refer to Section 4.2.2 of the Electricity Distribution Code.

Standard Nominal Voltage Variations				
Voltage Level (kV)	**Voltage Range for Time Periods**			**Impulse Voltage**
	Steady State	**Less than 1 minute**	**Less than 10 seconds**	
<1.0	+10% -6%	+14% -10%	Phase to Earth +50%-100% Phase to Phase +20%-100%	6kV peak
1-6.6	+/-6% (+/-10% Rural Areas)	+/-10%	Phase to Earth +80%-100% Phase to Phase +20%-100%	60kV peak
11				95kV peak
22				150kV peak
66	+/-10%	+/-15%	Phase to Earth +50%-100% Phase to Phase +20%-100%	325kV peak

Negative Sequence Voltage:

At a customer point of common coupling, refer to Section 4.6 of the Electricity Distribution Code.

Point of common coupling	**Maximum negative sequence voltage (% of nominal voltage)**	
	General	**Total 5min in every 30min period**
Customer's 3ph installation	1%	1-2%

At a terminal station connection point, refer to clause S5.1.7 of the National Electricity Rules.

Nominal Supply Voltage	**Maximum negative sequence voltage (% of nominal voltage)**			
	no contingency event	**contingency event**	**general**	**once per hour**
	30 min average	**30 min average**	**10 min average**	**1 min average**
22kV & 66kV	1.3%	1.3%	2.0%	2.5%

Power Factor:

At a terminal station connection point, refer to clause S5.3.5 of the National Electricity Rules and the particular Use of System Agreement.

Connection voltage	**Allowable variation in power factor for load greater than 30% of the maximum demand**
66kV	0.95 lagging to unity
22kV	0.90 lagging to 0.90 leading

Load Balance:

At a terminal station connection point, refer to clause S5.3.6 of the National Electricity Rules.

Connection voltage	Allowable variation in current in any phase to the average of the three phase currents
66kV	98-102%
22kV	95-105%

Disturbing Loads:

Refer to Section 4.8 of the Electricity Distribution Code.

4.8.1 A distributor must maintain voltage fluctuations at the point of common coupling at a level no greater than the levels specified in AS/NZ 61000.3.5:1998 and AS/NZ 61000.3.7:2001 as appropriate.

4.8.2 Subject to clause 4.8.3, a customer must ensure that the customer's equipment does not cause voltage fluctuations at the point of common coupling greater than the levels specified in AS/NZ 61000.3.5:1998 and AS/NZ 61000.3.7:2001 as appropriate.

4.8.3 If two or more customers' electrical installations are connected at the same point of common coupling, the maximum permissible contribution to voltage fluctuations allowable from each customer is to be determined in proportion to their respective maximum demand, unless otherwise agreed.

Voltage change limits as per Table 3 of AS 61000.3.7:2001:

Changes per hour, r	Voltage Change, %	
	HV (11, 22kV)	Subtransmission (66kV)*
r < 1	4	3
1 < r < 10	3	2.5
10 < r < 100	3	1.5
100 < r < 1000	1.25	1

In addition to the Electricity Distribution Code which the NER refers to, Technical Report TR61000-3-7:2008 supersedes AS61000.3.7:2001 and establishes a framework for the evaluation of voltage disturbances and flicker that involves allocation of limits according to planning levels which will be subject to AEMO allowances at the 66kV bus. The allocated harmonics and flicker levels to a particular load or generation are determined by proportioning the AEMO allocation amongst planned loads and known or currently being planned generators.

For wind and solar PV embedded generation there is a limit of 3% of change to voltage at the point of connection for 100% loss of generation. The 3% is the planning limit applied to this type of disturbance as per TR61000-3-7:2008.

For 66kV embedded solar PV generation, the voltage change in percent must be within short term flicker allocations. The loss of generation amount is set at 50% with a frequency of 0.5 changes per minute.