



**DISTRIBUTION SYSTEM
PLANNING REPORT**

December 2011

DISTRIBUTION SYSTEM PLANNING REPORT
TABLE OF CONTENTS

1.	INTRODUCTION	3
1.1	PURPOSE OF THIS PAPER.....	4
1.2	EXPRESSION OF INTEREST AND SUBMISSION FOR “NON-NETWORK” PROPOSAL	5
1.3	FINANCIAL INCENTIVES FOR “NON-NETWORK” SOLUTIONS	6
1.4	OVERVIEW OF DISTRIBUTION NETWORK PLANNING PROCESS	6
2.	PLANNING STANDARDS	8
2.1	OVERALL OBJECTIVE OF DISTRIBUTION NETWORK PLANNING	8
2.1.1	URBAN AREAS	8
2.1.2	SUBTRANSMISSION SUPPLY TO THE CBD AREAS.....	8
2.2	OVERALL APPROACH TO DISTRIBUTION NETWORK PLANNING	8
2.3	APPLICATION OF THE RISK-BASED DETERMINISTIC APPROACH TO DISTRIBUTION NETWORK PLANNING	9
2.4	DISTRIBUTION LOSSES	10
2.5	HISTORIC AND FORECAST DEMAND	10
3.	RISK ASSESSMENT AND OPTIONS FOR ALLEVIATION OF CONSTRAINTS.....	11
3.1	INTRODUCTION	11
3.2	INTERPRETING “ENERGY AT RISK”	12
3.3	BASE RELIABILITY STATISTICS FOR ZONE SUBSTATIONS AND SUBTRANSMISSION LINES	13
3.4	ASSET CONFIGURATION.....	13
3.5	EXPLANATION OF TERMS USED IN APPENDICES	13
4.	DISTRIBUTION NETWORK RELIABILITY IMPROVEMENTS.....	14
5.	LOAD FORECASTS, RISK ASSESSMENTS AND OPTIONS FOR ALLEVIATION OF CONSTRAINTS.....	17
5.1	ZONE SUBSTATIONS	17
5.2	SUB-TRANSMISSION LINES.....	25
6.	CBD SECURITY OF SUPPLY UPGRADE PLAN.....	31
6.1	CBD SECURITY OF SUPPLY UPGRADE PLAN	31
6.2	ADDITIONAL DISTRIBUTION LEVEL WORKS TO DELIVER N-1 SECURE.....	34
	APPENDIX 1 – MAP OF CITIPOWER ZONE SUBSTATION SUPPLY AREAS AND SUBTRANSMISSION LINES.....	36
	APPENDIX 2 – SUMMARY OF ZONE SUBSTATION CAPACITIES AND LOAD FORECASTS 2012-2016 (EXCLUDING PLANNED RESPONSE).....	37
	APPENDIX 3 – SUMMARY OF SUBTRANSMISSION LINES CAPACITIES AND LOAD FORECASTS 2012-2016 (EXCLUDING PLANNED RESPONSE).....	38
	APPENDIX 4 – SUMMARY OF ZONE SUBSTATION AND SUBTRANSMISSION LINE MAJOR PROJECT AUGMENTATIONS FOR 2012-2016 PERIOD.....	40
	GLOSSARY OF STATION NAME ABBREVIATIONS AND TERMS.....	41

1. INTRODUCTION

CitiPower owns and manages the electricity distribution network that connects to the shared transmission network and distributes electricity to approximately 313,000 customers in Melbourne's CBD and inner suburbs.

Subtransmission lines (both overhead and underground) connect to the terminal stations and supply CitiPower zone substations. Subtransmission lines are generally arranged in loops or meshes so that combinations of lines supply each zone substation, thereby providing security of supply in the event that individual lines are unavailable for service.

Zone substations transform the subtransmission line voltages (either 66kV or 22kV in CitiPower) to distribution voltages (either 11kV or 6.6kV in CitiPower) and supply the distribution substations via distribution feeders.

The CitiPower network comprises approximately 59,257 poles, 4,049km of overhead lines and 2,471 km of underground cables. CitiPower currently operates 38 zone substations, 84 subtransmission lines, approximately 3,331 distribution substations and approximately 658 distribution feeders

Appendix 1 shows the extent of CitiPower's network and indicates the approximate area supplied by each zone substations. Note that the area coverages are simplified to the extent that they do not show the overlaps between adjacent zone substation supply areas.

In Victoria each Distribution Network Business has responsibility for planning the augmentation of their distribution network. In order to continue to provide efficient, secure and reliable supply to its customers, CitiPower must plan augmentation of the network to match network capacity to customer demand. The need for augmentation is largely driven by customer peak demand growth and geographic shifts of demand due to urban redevelopment.

Clause 3.5 of the Distribution Code requires each of the distribution network businesses to provide an annual planning report as follows:-

3.5 Distribution System Planning Report

3.5.1 A **distributor** must submit to the **Commission** an annual report called the '*Distribution System Planning Report*' detailing how it plans over the following five calendar years:

- (a) to meet predicted **demand** for electricity **supplied** through its subtransmission lines, zone substations and high voltage lines;
- (b) to improve reliability to its **customers**; and
- (c) in the case of the **Melbourne CBD distributor** only, to implement any **CBD security of supply upgrade plan**.

3.5.2 In fulfilling the requirements of clause 3.5.1(a), the report must include the following information:

- (a) the historical and forecast **demand** from, and capacity of, each zone substation;
- (b) an assessment of the magnitude, probability and impact of loss of **load** for each subtransmission line and zone substation;
- (c) the **distributor's** planning standards;
- (d) a description of feasible options for meeting forecast **demand** including opportunities for **embedded generation** and **demand** management;
- (e) where a preferred option for meeting forecast **demand** has been identified, a reasonably detailed description of that option, including estimated costs; and
- (f) the availability of contributions from the **distributor to embedded generators** or **customers** to reduce forecast **demand** and defer or avoid **augmentation** of the **distributor's distribution system**.

3.5.3 In fulfilling the requirements of clause 3.5.1(b), the report must include the

following information:

- (a) a description of the nature, timing, cost and expected impact on performance of the **distributor's** reliability improvement programs; and
- (b) an evaluation of the reliability improvement programs undertaken in the preceding year.

3.5.3A In fulfilling the requirements of clause 3.5.1(c) (if applicable), the report must include the following information:

- (a) an outline of the capital and other works carried out in the preceding year in implementing the Melbourne **CBD security of supply upgrade plan**;
- (b) an evaluation of whether the relevant security of supply objectives specified in the Melbourne **CBD security of supply upgrade plan** have been achieved in the preceding year; and
- (c) an outline of the capital and other works connected with the security of supply objectives proposed to be carried out in the following 5 years.

3.5.4 Each **distributor** must publish the *Distribution System Planning Report* on its website and, on request by a **customer**, provide the **customer** with a copy. The **distributor** may impose a charge (determined by reference to its **approved statement of charges**) for providing a **customer** with a copy of the report.

The assessment presented in this report seeks to provide the information required by section 3.5 of the Distribution Code, however, it is not a detailed planning analysis but a high-level description of the expected balance between capacity and demand at each zone substation and subtransmission line over the forecast period.

Data presented in this report may indicate an emerging major constraint. Therefore, this report provides a means of identifying those zone substations and subtransmission lines where more detailed analysis of risks and options for remedial action are required.

This report also provides preliminary information on potential opportunities to prospective proponents of alternatives to network augmentations at stations where remedial action may be required. Providing this information to the market should facilitate the efficient development of the network to best meet the needs of customers.

Parties seeking further information about these potential opportunities, or any other matter contained in this report should contact CitiPower via the company website at www.citipower.com.au or

Neil Gascoigne, System Planning & Secondary Systems Manager, CitiPower/Powercor, phone 9683-4472.

1.1 Purpose of this paper

This report sets out information to demonstrate CitiPower's good asset management consistent with the requirements of section 3.1 of the Electricity Distribution Code and to identify those areas of the network likely to become constrained within the planning horizon. This transparent approach gives all stakeholders an opportunity to participate in the distribution planning processes and invites input and alternative proposals from interested parties to ensure efficient investment in the capacity of the CitiPower distribution network.

These arrangements are aimed at fostering efficient and coordinated development of distribution networks. CitiPower is best placed to determine the optimum level of investment in, and configuration of, its subtransmission system capacity, having regard to:

- the needs and preferences of its customers (the end consumers of electricity);
- the relative costs and benefits associated with alternative distribution and subtransmission development strategies as well as alternative strategies aimed at delivering a level of supply reliability in accordance with customer needs; and
- the direct and indirect incentives (and penalties) faced by CitiPower in relation to the reliability of its distribution network facilities.

Section 3.1(b) of the Distribution Code states:

“A distributor must use best endeavours to develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution system assets ...in a way which minimises costs to customers taking into account distribution losses.”

It is important to recognise factors other than direct costs when judging the relative efficiency of various network augmentation proposals. Those other factors all contribute to the total life cycle cost of the augmentation assets.

For the purpose of this report, it is assumed that the additions to zone substation capacity and subtransmission capacity generally use standard components or standardised techniques. In the case of non-network proposals or where stakeholders propose network solutions using equipment or techniques other than the proven CitiPower standard, a thorough investigation of life cycle costs and reliability will be required in considering such alternatives.

1.2 Expression of Interest and Submission for “Non-Network” Proposal

One of the purposes of this document is to provide information to proponents of non-network solutions (such as embedded generation or demand management) to emerging network constraints. As noted in further detail in Chapter 2 below, CitiPower’s aim is to develop the distribution network in a manner that maximises net economic benefit. To this end, proponents of non-network solutions to the emerging network constraints identified in this report are invited to lodge expressions of interest with CitiPower.

Proponents of non-network proposals should make initial contact as soon as possible, to ensure that sufficient time is available to fully assess feasible network and non-network potential solutions. It should be noted, however, that parts of the network experience volatile load growth. This is usually a direct consequence of economic and demographic factors that are difficult to foresee and model at high levels. As such it is essential that alternatives to network solutions are presented by proponents in sufficient time to allow for their thorough evaluation, planning and implementation.

To assist in the assessment of non-network solutions, proponents are invited to lodge a detailed submission to CitiPower. Submission should be informed by earlier discussions and should include all the following details about the proposal:

1. Proponent name and contact details;
2. A detailed description of the proposal;

3. Electrical layout schematics;
4. A firm nominated site;
5. The capacity provided;
6. Fault level contribution, load flows, and stability studies (if applicable);
7. A commissioning date with contingency specified;
8. Availability and reliability performance benchmarks;
9. Network interface requirements;
10. The economic life of the proposal;
11. Banker / financier commitment;
12. Proposed operational and contractual arrangements;
13. Any special conditions to be included in a contract;
14. Proof of planning application approval.

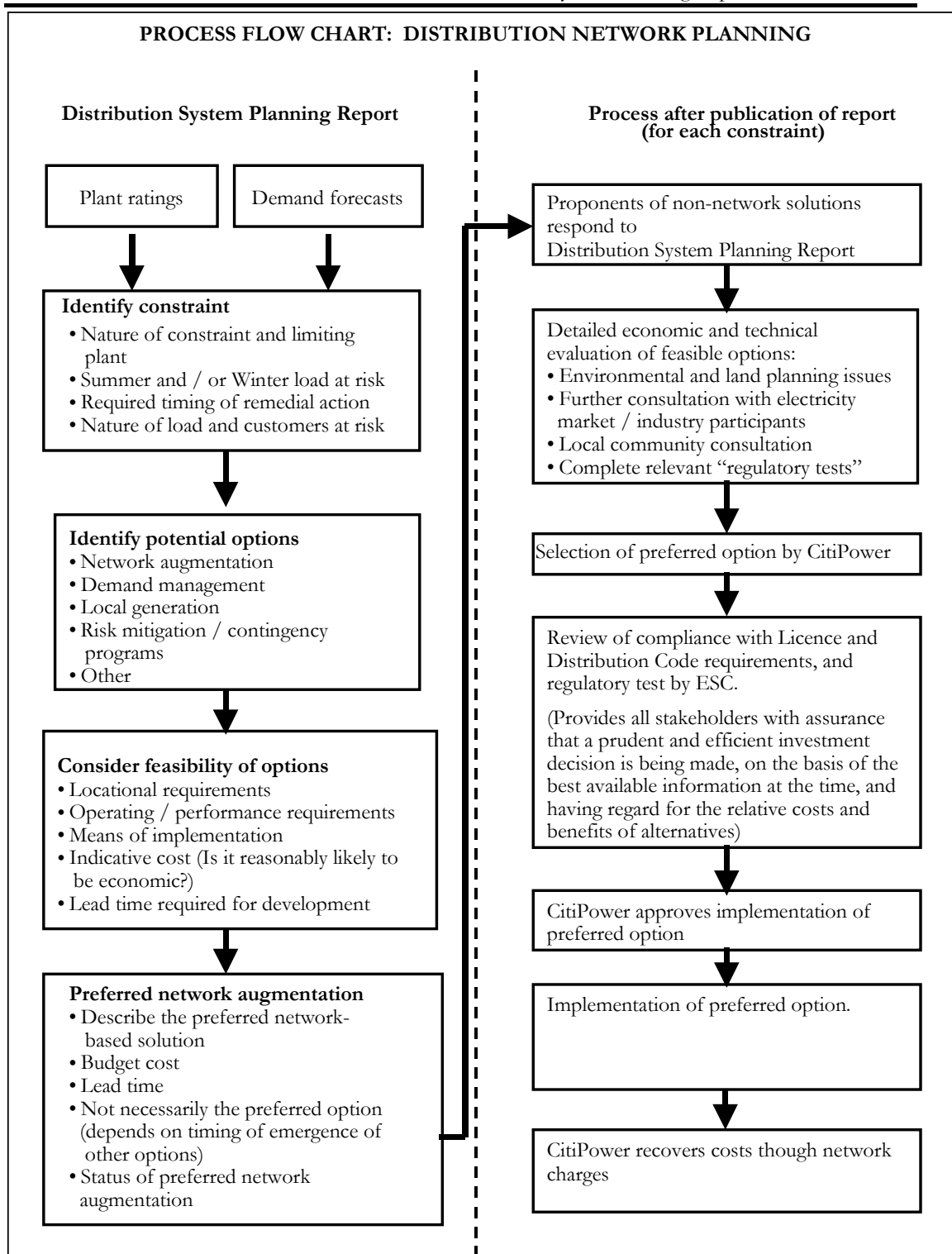
Any network reinforcement costs required to accommodate the non-network solution will generally be borne by the proponents. All proposals must satisfy the requirements of any applicable Codes and Regulations.

1.3 Financial Incentives for “Non-Network” Solutions

If it can be demonstrated that the proposed non-network solution provides a net economic benefit over a network solution, CitiPower will be prepared to negotiate a financial incentive to share these benefits with the proposer of such a scheme subject to verification of the financial arrangements by the Essential Services Commission where appropriate.

1.4 Overview of Distribution Network Planning Process

The flow chart below provides a summary of the distribution network planning and augmentation process currently undertaken within CitiPower.



2. PLANNING STANDARDS

2.1 Overall objective of distribution network planning

In terms of overall planning objectives at the zone substation and subtransmission system level, CitiPower aims to achieve a network that is capable of satisfactorily supplying customers after any single contingency event at the 50th percentile¹ demand forecast. This may entail a short interruption to customers. This standard provides for the planned or unplanned removal from service of any line, transformer, circuit breaker, etc at the time of 50th percentile maximum demand loading on the station/system, in a manner such that:

- there is no requirement to shed customer load for long durations;
- voltage levels on the secondary buses of zone substations are maintained within acceptable Code limits; and
- the loading on all remaining in-service elements is within their operational limits.

2.1.1 Urban Areas

CitiPower designs the network with the aim of securing all loads within a short interval following a first order (N-1) contingency.

2.1.2 Subtransmission Supply to the CBD Areas

In March 2008 the Essential Services Commission amended the Electricity Distribution Code to oblige CitiPower to deliver a project to deliver a higher level of security to many of the Melbourne CBD customers.

In August 2008 the Essential Services Commission approved the Plan submitted by CitiPower to improve the security of supply to the Melbourne 66kV CBD network. Details of the security improvement Plan can be found in section 6.1 of this report.

CitiPower takes into account a risk-based deterministic approach when planning the sub-transmission and distribution system development. Section 2.2 discusses the way in which this approach achieves efficient and equitable outcomes.

In addition, investment decisions have regard to the costs and benefits of non-network alternatives to augmentation. Such alternatives include, but are not necessarily limited to, demand-side management and embedded generation.

2.2 Overall approach to distribution network planning

In general there are two alternative approaches to network planning.

Deterministic planning standards call for zero interruptions to customer supply following any single outage of a network element. In this scenario any failure or outage of individual network

¹ Refer Section 3 for explanation of “percentile demand”.

elements (known as the “N-1” condition) can be tolerated without customer impact due to sufficient redundancy built into the distribution network. Adherence to a deterministic approach using the N-1 criteria can imply an inefficient network investment, as the risk of customer interruption is driven to zero by the provision of reserve or backup capacity at costs that are not judged against the cost of likely interruptions or alternatives.

The second alternative is a probabilistic planning approach. Under the probabilistic approach, the deterministic N-1 criterion is relaxed, and simulation studies are undertaken to assess the amount of energy that would not be supplied if an element of the network is out of service. By taking into account the energy not supplied this approach can lead to the deferral of capital works that would otherwise proceed if a deterministic standard were strictly applied. This is because:

- in a network planned in accordance with the probabilistic approach, there are conditions under which all the load cannot be supplied with a network element out of service (hence the N-1 criterion is not met); however
- under these conditions, the actual load at risk may be very small when considering the probability of a forced outage of a particular element of the subtransmission network.

CitiPower considers a risk-based deterministic approach appropriate, rather than a strict application of the deterministic criteria. The risk-based deterministic approach takes into consideration:

- The number of transmission connection points used to supply a significant area of load (i.e. a CBD).
- A limit to the load at risk from any one event.

2.3 Application of the risk-based deterministic approach to distribution network planning

The risk-based deterministic planning approach involves assessing the amount of load and energy that would not be supplied if an element of the network were out of service, therefore providing 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, this can lead to deferral of significant network capital works that would otherwise proceed if prescriptive deterministic standards were applied.

The quantity of energy at risk is a critical parameter in assessing a prospective network investment. Risk-based deterministic network planning aims to strike an economic balance between:

- the cost of providing additional network capacity to remove any constraints; and
- the potential cost of having some exposure to loading levels beyond the network’s firm capability.

In other words, recognising that very extreme loading conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that these extreme loadings occur co-incidentally with a plant outage. Rather, the risk-based deterministic approach indicates that network augmentation should take place only when loading has increased to the extent that the energy at risk justifies expenditure on network augmentation to reduce the level of energy at risk or has reached a set limit..

However, implicit in the risk-based deterministic approach is acceptance of the risk that there may be circumstances when the planned station capacity will be insufficient to meet actual demand. The extent to which investment should be committed to mitigate that risk is ultimately a matter of judgment, having regard for:

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

2.4 Distribution Losses

CitiPower has a process to identify, justify and implement augmentation plans to address network constraints. Whilst loss reduction alone is not the main contributing factor in the decision of the preferred option, it is seen as the deciding factor if all other factors are equal. CitiPower as part of its plant selection process takes into account the cost of losses in its evaluation for transformer purchase.

2.5 Historic And Forecast Demand

CitiPower produces a series of load and demand forecasts each year for a range of purposes including

- Distribution network planning
- Transmission system connection asset planning

The forecasts are based on historic actual load and demand values recorded across the distribution network. Actual values are corrected for the prevailing network and environmental conditions to produce values that are representative of a number of different weather scenarios.

While the historic demand values shown in Appendix 2 are actual recorded values, it is important for future forecasts that these actual peak demand values are corrected or normalised in accordance with the relevant temperatures experienced across any given summer loading period. As peak demand in CitiPower is very temperature dependant this correction is essential to determine the real underlying peak demand growth year by year, which is the basis for future forecasts and investment decisions.

This report considers the 50th percentile maximum demand. It is important to recognise that the 50th percentile demand forecast relates to a maximum average temperature that will be exceeded, on average, once every two years. By definition therefore, actual demand in any given year has a 50% probability of being higher than the 50th percentile demand forecast.² The 50th percentile

² Consequently there is also a 50% probability that demand will not reach forecast.

forecast can therefore be considered to be a forecast of the “most-likely” level of demand, bearing in mind that actual demand will vary depending on temperature.

To obtain forward projections, these sets of values are trended forward and added to known and predicted loads that may be connected to the network. Considerable effort is used to collect information that can be used to estimate the load requirements (and timing of those loads) for use in the load and demand forecasts. This information consists of the estimated load requirements for planned, committed and developments under-construction across the CitiPower service area.

As load and demand is also a function of economic activity, information is also obtained from sources such as the National Institute of Industry and Economic Research (NIEIR) and used to compare with the forecasts.

3. RISK ASSESSMENT AND OPTIONS FOR ALLEVIATION OF CONSTRAINTS

3.1 Introduction

The assessment presented is not a detailed planning analysis, but a high-level description of the expected balance between capacity and demand over the forecast period. Data presented in this high-level analysis may indicate an emerging major constraint. Therefore, this high-level assessment provides a means of identifying those stations or lines where more detailed analyses of risks and options for remedial action are required.

It is emphasised that this high-level analysis focuses on risks to supply reliability that relate to the capacity and reliability of zone substations and subtransmission lines only. There are typically risks to supply reliability associated with the performance and capacity of smaller plant items. However, these smaller items involve relatively lower capital expenditure, the deferral of which is unlikely to provide a sufficiently high benefit, of itself, to justify the employment of non-network alternatives.

In addition, capital expenditure is required from time to time to address fault level issues. This expenditure is driven chiefly by mandatory health and safety standards, and does not relate to zone substation capacity. Fault level issues are therefore not within the scope of this report, however, the analysis of feasible and preferred options for increasing capacity will, where appropriate, have due regard for issues relating to fault level control.

The following key data are presented in this Section for each Zone Substation (and Subtransmission Line):

- ***Energy at risk:*** This is the amount of energy that would not be supplied from a zone substation if a major outage³ of a transformer occurs at that station in that particular year, the outage has a mean duration of 2.5 months and no other mitigation action is taken. This statistic provides an indication of magnitude of loss of load that would arise in the unlikely event of a major outage of a transformer without taking into account planned augmentation or operational action, such as load transfers to other supply points, to mitigate the impact of the outage.

³ The term ‘Major Outage’ refers to an outage that has a duration of 2.5 months, typically due to a significant failure within the transformer.

The same definitions apply to subtransmission lines, however, the mean duration of an outage due to a significant failure is 1 week for overhead subtransmission lines and 8 weeks for underground subtransmission lines

Estimates of energy at risk are based on the 50th percentile demand forecasts as per Section 2 .

3.2 Interpreting “energy at risk”

As noted above, “energy at risk” is an estimate of the amount of energy that would not be supplied if one transformer was out of service during the critical loading season(s).

The capability of a zone substation with one transformer out of service is referred to as its “N minus 1” rating. The capability of the station with all transformers in service is referred to as its “N” rating. The relationship between the N and N-1 ratings of a station and the energy at risk is depicted in figure 2 below.

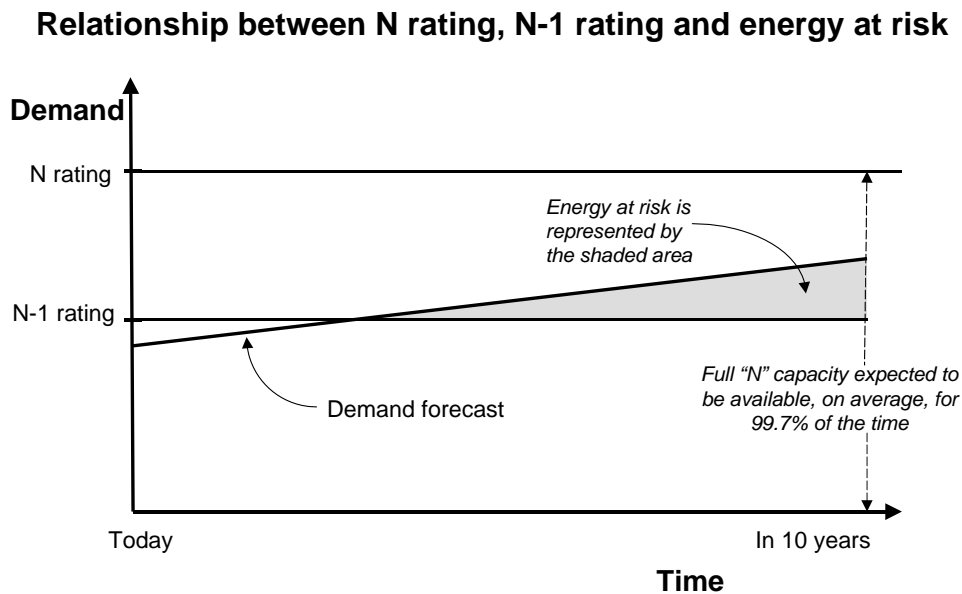


Figure 1 - Energy at Risk under N-1 Conditions

Note that:

- Under normal operating conditions, there will typically be more than adequate zone substation capacity to supply all demand.
- The risk of prolonged outages of a zone substation transformer leading to load interruption is typically very low.

The capability of a subtransmission line network with one line out of service is referred to as the (N-1) condition for that subtransmission network.

- Under normal operating conditions, there will typically be more than adequate line capacity to supply all demand.

- The risk of prolonged outages of a subtransmission line leading to load interruption is typically very low and is dependant upon the length of line exposed and the environment in which the line operates.

In estimating the expected cost of plant outages, this report considers the first order contingency condition (“N-1”) only.

3.3 Base reliability statistics for zone substations and subtransmission lines

Estimates of the expected unserved energy at each zone substation must be based on the expected reliability performance of the relevant transformers.

The base reliability data for zone substation transformers (and subtransmission lines) has been estimated using available CitiPower historic fault and outage records.

3.4 Asset Configuration

CitiPower zone substation and subtransmission line assets are generally arranged in loop or mesh configuration. Mesh arrangement is used within the CBD and loop outside the CBD.

In general for both cases, loss of a line or loss of a transformer does not automatically result in customer interruption as the remaining transformers and lines provide continuity of supply.

3.5 Explanation of terms used in Appendices

The following is a list of terms used in the Appendices and their explanations.

1. **Firm rating** is the nameplate station output capacity with outage of one transformer.
2. **N Cyclic rating** is the station output capacity with all transformers in service. Cyclic ratings assume that the load follows a daily pattern and are calculated using load curves appropriate to the season. Cyclic ratings also take into consideration the thermal inertia of the plant.
3. **N-1 Cyclic rating** is the cyclic station output capability with an outage of one transformer.
4. **Capacity of Line (Amps)** is the line current rating which takes into consideration the type of line, conductor materials, allowable insulation temperature, effect of adjacent lines, allowable temperature rise and ambient conditions. It should be noted that CitiPower operates many types of underground cables in its subtransmission system. The different types of underground cables have varying operating parameters that in turn define their ratings.
5. **MVA above either WCR or SCR** is the amount of demand forecast to exceed the Winter Cyclic Rating or the Summer Cyclic Rating.
6. **% Above Capacity** is the percentage by which the forecast maximum demand exceeds the N-1 cyclic rating.
7. **Energy at risk** is the amount of energy that would not be supplied if a major outage of a transformer occurs at the station in that particular year, the outage has a duration of 2.5 months, and no other mitigation action is taken.
8. **Annual hours per year at risk** is the number of hours in a year during which the 50th percentile demand forecast exceeds the N-1 capability rating.

4. DISTRIBUTION NETWORK RELIABILITY IMPROVEMENTS

Clause 3.5.1 (b) of the Distribution Code requires that:

A **distributor** must submit to the **Commission** an annual report called the '*Distribution System Planning Report*' detailing how it plans to over the following five calendar years to improve reliability to its **customers**.

Clause 3.5.3 states that

In fulfilling the requirements of clause 3.5.1(b), the report must include the following information:

- (a) a description of the nature, timing, cost and expected impact on performance of the **distributor's** reliability improvement programs; and
- (b) an evaluation of the reliability improvement programs undertaken in the preceding year.

The reliability targets for CitiPower as per the AER determination of October 2010 "Victorian Electricity Distribution Network Service Providers - Distribution determination 2011–2015" are stated in Table 1 below:

AER TARGET PERFORMANCE (Minutes Off Supply)⁴ SAIDI		
Network Segment		2011
CBD	Unplanned	11.27
Urban	Unplanned	22.36

Table 1 - CitiPower Reliability Targets

⁴ Minutes Off Supply - Average unplanned minutes a customer could expect to be disconnected from supply in a year. This includes unplanned interruptions due to faults caused by storms, lightning, car accidents, animals, etc. Targets as per "Victorian Electricity Distribution Network Service Providers - Distribution determination 2011–2015" October 2010 Page 724 Table 15.23

The following Table 3 indicates the forecast reliability performance to be achieved by CitiPower in 2011 based on figures as at 31 October 2011.

2011 FORECAST PERFORMANCE ⁵			
Minutes Off Supply			
Network Segment		AER Target 2011	2011 Forecast at end October 2011
CBD	Unplanned	11.27	6.46
Urban	Unplanned	22.36	23.19
Total Network	Unplanned	20.40	20.19

Table 3 - 2010 Forecast Performance

Actual network reliability performance is the result of many factors and reflects the outcomes of numerous programs and practices right across the network. In addition to the works carried out as per the composite reliability program, CitiPower continues to refine and target existing asset management programs in order to maximise stakeholder benefits including supply reliability.

CitiPower aims to achieve long term and sustainable reliability improvements through combination of existing asset management strategies and a composite reliability improvement program which includes:

- Installation of remote operable switches on distribution feeders
- Reduction of exposure to faults on overhead distribution feeders by reconductoring with covered conductors
- Undergrounding of overhead distribution feeder sections
- Implementing CitiPower's Vegetation Management Plan by clearing all private trees to achieve required clearance and performing vegetation risk management work on critical subtransmission and high voltage feeders.
- Covering of overhead distribution feeder spans in the vicinity of high risk vegetation
- Automation of high voltage feeders to minimise fault restoration time.
- Insulator washing of subtransmission and selected HV lines on a regular basis determined by the strategic importance of the line, types of insulators and prevailing weather conditions.
- Testing and routine maintenance of 66kV oil filled cable forming part of the 66KV sub-transmission network of the CBD.
- Incorporation of animal mitigation measures in standard construction methods
- Replacement of ageing relays at strategic zone sub stations to improve reliability of protection schemes.

Some of the reliability improvement programs that were implemented in 2011 are:

- On-line oil dehydration has been carried out on 3 transformers at 2 zone substations.
- Testing and routine maintenance of 66kV oil filled cable forming part of the 66kV sub-transmission network of the CBD.

⁵ Forecasts based on actual performance to end of October less excluded events

- Thermo-vision audit of equipment within indoor distribution substations is now undertaken in all CitiPower CBD indoor distribution substations as a scheduled maintenance activity.
- Insulator washing of Subtransmission and selected HV lines is scheduled for summer each year on a priority basis determined by the strategic importance of the line, types of insulators and prevailing weather conditions. Line conditions and environmental factors are reviewed in November and January each year to determine the optimum time to commence washing.
- Eight temperature indicators on 4 Zone Substation power transformers have been replaced to ensure correct operation of cooling fans.
- Twenty portable auxiliary cooling fans are deployed at various substations as required.
- Replacement of older protection relays has been undertaken at zone substation AP.
- Installation of remotely operable Reclosers on selected feeders to reduce the impact of interruptions and aid in the restoration of customers on these feeders.
- Replacement of 1 aged power transformer has been undertaken at zone substation R.
- Three 66KV transformer bushings are to be replaced at zone substation AR. Work to be completed by end of December 2011.

Evaluation of the effectiveness of one year's reliability improvement initiatives should be considered in the context of the longer term goals stipulated above and the volatility caused by uncontrollable events such as severe storms and the effect of third party events.

5. LOAD FORECASTS, RISK ASSESSMENTS AND OPTIONS FOR ALLEVIATION OF CONSTRAINTS

The following sections present a high level description of the risk assessment of CitiPower zone substations and subtransmission lines operating greater than 5 percent above their firm summer or winter rating for the next 5 years. It should be noted that the energy at risk calculations are based on excluding any planned responses to mitigate the risk.

All other CitiPower zone substations and subtransmission lines not specifically mentioned below either have loadings below their ratings or their loadings above ratings are minimal which can be covered by the available load transfer capability via high voltage network to adjacent zone substations. Thus all customers can be supplied following the first order outage contingency in the current review period.

5.1 Zone Substations

AR Zone Substation, Armadale

Station Rating & supply area

Armadale zone substation has a summer N-1 rating of 32.9MVA comprised of two 20/30MVA transformers operating at 66/11kV. The Zone Substation supplies the Armadale and Malvern areas.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

AR	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	44	53	64	76	90
Annual hours at risk (hrs)	23	27	32	35	39

Network solutions to manage load at risk

- Load reduction involving transfer of load via 11kV links to adjacent stations.

The load at risk shown above is before implementation of any network risk mitigation strategies. Although the expected demand over the next five years will exceed the station's N-1 rating, with the implementation of the above proposed network solutions to cover this shortfall, it is expected that all customers can be supplied following the outage of a major plant item during this planning period.

B Zone Substation, Collingwood

Station Rating & supply area

B zone substation has a summer N-1 rating of 29.0MVA comprised of two 20/27MVA transformers operating at 66/11kV. The Zone Substation supplies the Collingwood and Abbotsford areas.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

B	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	270	342	427	525	636
Annual hours at risk (hrs)	128	152	180	208	236

Network solutions to manage load at risk

- Load reduction involving transfer of load via 11kV links to adjacent stations..
- Establish B 3rd transformer not earlier than 2016 at an estimated cost of \$2.5M

The load at risk shown above is before implementation of any network risk mitigation strategies. Although the expected demand over the next five years will exceed the station's N-1 rating, with the implementation of the above proposed network solutions to cover this shortfall, it is expected that all customers can be supplied following the outage of a major plant item during this planning period.

BS (previously BSBQ) Zone Substation, Bouverie StStation Rating & supply area

Bouverie St zone substation has a summer N-1 rating of 25.4MVA comprised of three 10MVA transformers operating at 22/11kV. The Zone Substation supplies the Carlton, Melbourne and Parkville areas.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

BSBQ	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	13	54	110	206	352
Annual hours at risk (hrs)	16	48	88	139	215

Network solutions to manage load at risk under N-1 conditions

- Load reduction involving transfer of load via 11kV links to adjacent stations.
- Enter into negotiations with Aurora Energy for support agreement covering the operation of the 14.8 MVA hospital generators to the end of 2014 at an estimated cost of \$300K subject to negotiations.

The load at risk as shown above is before implementation of any network risk mitigation strategies. The expected demand over the next five years will exceed the station's N-1 rating, and with the implementation of all the above proposed network solutions to cover this shortfall, it is expected that all customers can be supplied following the outage of a major plant item during this planning period.

CL Zone Substation, Camberwell

Station Rating & supply area

Camberwell zone substation has a summer N-1 rating of 65.8MVA comprised of two 20/30MVA transformers and one 20/27MVA transformer operating at 66/11kV. The Zone Substation supplies the Camberwell and Hawthorn areas.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

CL	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	9	21	43	78	124
Annual hours at risk (hrs)	5	9	15	23	31

Network solutions to manage load at risk under N-1 conditions

Load reduction involving transfer of load via 11kV links to adjacent stations.

The load at risk as shown above is before implementation of any network risk mitigation strategies. The expected demand over the next five years will exceed the station's N-1 rating, and with the implementation of all the above proposed network solutions to cover this shortfall, it is expected that all customers can be supplied following the outage of a major plant item during this planning period.

DA Zone Substation, Docklands Area

Station Rating & supply area

Docklands zone substation has a summer N-1 rating of 29.2MVA comprised of three 10/13.5MVA transformers operating at 22/11kV. The Zone Substation supplies the Docklands and North Melbourne areas.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

DA	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	565	1522	3955	9283	17605
Annual hours at risk (hrs)	325	801	2100	4003	5663

Network solutions to manage load at risk under N-1 conditions

- Load reduction involving transfer of load via 11kV links to adjacent stations.
- Establish a plant protection scheme at DA by the end of 2012 at an estimated cost of \$150K
- Establish 11kV link between DA to WG to facilitate a permanent load transfer by the end of 2012 in conjunction with a customer connection application. This project is subject to customer acceptance prior to proceeding. Alternatively, establish 11kV link between

DA to WG to facilitate a permanent load transfer by the end of 2013 at an estimated cost of \$500K. This is not subject to customer acceptance.

- Establish DA zone substation into a 66kV substation by the end of 2016 at an estimated cost of \$16M. This timing co-ordinates with the offloading of the WMTS66 connection point onto the upgraded BTS66 connection point (refer to the 2011 Transmission Connection Planning Report).

The load at risk as shown above is before implementation of any network risk mitigation strategies. The expected demand over the next five years will exceed the station's N-1 rating, and with the implementation of all the above proposed network solutions to cover this shortfall, it is expected that not all customers can be supplied following the outage of a major plant item during the planning period between 2012 and 2013.

L Zone Substation, Deepdene

Station Rating & supply area

L zone substation has a summer N-1 rating of 32.1MVA comprised of two 20/30MVA transformers operating at 66/11kV. The Zone Substation supplies the Balwyn, Canterbury and Kew areas.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

L	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	172	267	308	354	405
Annual hours at risk (hrs)	55	78	88	99	110

Network solutions to manage load at risk under N-1 conditions

- Load reduction involving transfer of load via 11kV links to adjacent stations.
- Establish a 6 MVAR capacitor bank at L zone substation by the end of 2013 at an estimated cost of \$570K

The load at risk shown above is before implementation of any network risk mitigation strategies. Although the expected demand over the next five years will exceed the station's N-1 rating, with the implementation of the above proposed network solutions to cover this shortfall, it is expected that all customers can be supplied following the outage of a major plant item during this planning period

LS Zone Substation, Laurens Street

Station Rating & supply area

Laurens Street zone substation has a summer N-1 rating of 23.6MVA comprised of two 10MVA transformers and one 13.5MVA transformer operating at 22/6.6kV. The Zone Substation supplies the North Melbourne and Parkville areas.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

LS	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	14	39	87	164	278
Annual hours at risk (hrs)	19	41	76	118	173

Network solutions to manage load at risk under N-1 conditions

- Load reduction involving transfer of load via 11kV links to adjacent stations.
- Establish 11kV link between LS and BQ to facilitate a permanent load transfer by the end of 2018 at an estimated cost of \$3.3M

The load at risk shown above is before implementation of any network risk mitigation strategies. Although the expected demand over the next five years will exceed the station's N-1 rating, with the implementation of the above proposed network solutions to cover this shortfall, it is expected that not all customers can be supplied following the outage of a major plant item from 2013 in this planning period

NR Zone Substation, North Richmond

Station Rating & supply area

North Richmond zone substation has a summer N-1 rating of 57.4MVA comprised of two 23/28MVA transformers and one 20/27MVA transformer operating at 66/11kV. The Zone Substation supplies the Richmond and Abbotsford areas. Due to the lower than normal impedance of two of the three transformers at NR, one of the NR transformers is on hot standby with the 11kV transformer CB opened.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

NR	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	5	13	39	76	115
Annual hours at risk (hrs)	4	8	20	32	42

Network solutions to manage load at risk under N-1 conditions

- Load reduction involving transfer of load via 11kV links to adjacent stations.
- Establish normally open-auto close scheme on bus tie CB by end of 2013 at an estimated cost of \$150K.

The load at risk shown above is before implementation of any network risk mitigation strategies. Although the expected demand over the next five years will exceed the station's N-1 rating, with the implementation of the above proposed network solutions to cover this shortfall, it is

expected that all customers can be supplied following the outage of a major plant item during this planning period

Q Zone Substation, Kew

Station Rating & supply area

Kew zone substation has a summer N-1 rating of 30.7MVA comprised of two 20/30MVA transformers operating at 66/11kV. The Zone Substation supplies the Kew area.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

Q	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	218	276	338	417	516
Annual hours at risk (hrs)	71	88	112	141	176

Network solutions to manage load at risk under N-1 conditions

- Load reduction involving transfer of load via 11kV links to adjacent stations.
- Establish a 6 MVAR capacitor bank at Q zone substation by the end of 2013 at an estimated cost of \$570K

The load at risk shown above is before implementation of any network risk mitigation strategies. Although the expected demand over the next five years will exceed the station's N-1 rating, with the implementation of the above proposed network solutions to cover this shortfall, it is expected that all customers can be supplied following the outage of a major plant item.

R Zone Substation, Richmond

Station Rating & supply area

Richmond zone substation has a summer N-1 rating of 31.4MVA comprised of three 10/14MVA transformers operating at 22/11kV. The Zone Substation supplies the Richmond area.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

R	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	110	208	337	512	737
Annual hours at risk (hrs)	62	102	145	198	252

Network solutions to manage load at risk under N-1 conditions

- Load reduction involving transfer of load via 11kV links to adjacent stations.

- Establish 11kV link between R to TK to facilitate a permanent load transfer by the end of 2012 in conjunction with a customer connection application. This project is subject to customer acceptance prior to proceeding. Alternatively, establish 11kV link between R to TK to facilitate a permanent load transfer by the end of 2013 at an estimated cost of \$2.5M. This is not subject to customer acceptance.

The load at risk shown above is before implementation of any network risk mitigation strategies. Although the expected demand over the next five years will exceed the station's N-1 rating, with the implementation of the above proposed network solutions to cover this shortfall, it is expected that all customers can be supplied following the outage of a major plant item during this planning period

RD Zone Substation, Riversdale

Station Rating & supply area

Riversdale zone substation has a summer N-1 rating of 30.6MVA comprised of two 20/30MVA transformers operating at 66/11kV. The Zone Substation supplies the Camberwell area.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

RD	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	359	396	419	442	467
Annual hours at risk (hrs)	107	114	119	125	130

Network solutions to manage load at risk under N-1 conditions

- Load reduction involving transfer of load via 11kV links to adjacent stations.

The load at risk shown above is before implementation of any network risk mitigation strategies. The expected demand over the next five years will exceed the station's N-1 rating even with the implementation of the above proposed network solutions to cover this shortfall, therefore it is possible that not all customers can be supplied following the outage of a major plant item from 2013 in this planning period.

SK Zone Substation, St Kilda

Station Rating & supply area

St.Kilda zone substation has a summer N-1 rating of 62.6MVA comprised of three 20/30MVA transformers operating at 66/11kV. The Zone Substation supplies the St.Kilda area. . Due to the connection of a cogenerator, one of the SK transformers is on hot standby with the 11kV transformer CB opened.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

SK	2012	2013	2014	2015	2016
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Annual energy at risk (MWh)	9	20	36	58	86
Annual hours at risk (hrs)	5	9	15	23	31

Network solutions to manage load at risk under N-1 conditions

- Load reduction involving transfer of load via 11kV links to adjacent stations.
- Establish normally open-auto close scheme on bus tie CB by end of 2013 at an estimated cost of \$150K

The load at risk shown above is before implementation of any network risk mitigation strategies. Although the expected demand over the next five years will exceed the station's N-1 rating, with the implementation of the above proposed network solutions to cover this shortfall, it is expected that all customers can be supplied following the outage of a major plant item during this planning period

WB Zone Substation, West Brunswick

Station Rating & supply area

West Brunswick zone substation has a summer N-1 rating of 26.4MVA comprised of two 20/30MVA transformers operating at 66/6.6kV. The Zone Substation supplies the West Brunswick area

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

WB	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	10	17	28	42	60
Annual hours at risk (hrs)	12	17	25	34	41

Network solutions to manage load at risk under N-1 conditions

- Load reduction involving transfer of load via 11kV links to adjacent stations.

The load at risk shown above is before implementation of any network risk mitigation strategies. Although the expected demand over the next five years will exceed the station's N-1 rating, with the implementation of the above proposed network solutions to cover this shortfall, it is expected that all customers can be supplied following the outage of a major plant item during this planning period

5.2 Sub-Transmission Lines

RTS-TK-BC-AR-RTS 66KV SUBTRANSMISSION LOOP

Supply points & line loading

The RTS-TK-BC-AR-RTS subtransmission loop supplies the Toorak (TK), Balaclava (BC), and Armadale (AR) zone substations fed from Richmond Terminal Station (RTS) at 66kV.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

RTS - AR	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	353	478	634	774	934
Annual hours at risk (hrs)	51	66	83	98	113

RTS - TK	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	105	157	227	270	317
Annual hours at risk (hrs)	20	28	36	40	44

BC - AR	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	135	195	271	339	421
Annual hours at risk (hrs)	47	56	68	80	93

Network solutions to manage load at risk

- Load reduction involving transfer of load via 11kV links to adjacent stations.
- Establish a plant protection scheme at AR by the end of 2013 at an estimated cost of \$200K.
- Establish a plant protection scheme at TK by the end of 2013 at an estimated cost of \$200K.
- Reconductor RTS-AR 66kV line (rack to tower) section by the end of 2016 at an estimated cost of \$430K.
- Uprate RTS-AR 66kV line (tower section) section by the end of 2016. An estimated cost of for this option is still to be determined.
- Uprate bus element in TK by the end of 2016 at an estimated cost of \$150K.
- Reconductor RTS-TK (1.8km) 66kV line by the end of 2016 at an estimated cost of \$700K.

Although the expected demand of the above lines over the next five years will exceed their corresponding line ratings, with the implementation of the above proposed network solutions to cover this shortfall, it is expected that all customers can be supplied following the outage of a major line during this planning period.

RTS-CW-B-NR-RTS 66KV SUBTRANSMISSION LOOP

Supply points & line loading

The RTS-CW-B-NR-RTS subtransmission loop supplies the Collingwood (CW), Collinwood (B), and North Richmond (NR) zone substations fed from Richmond Terminal Station (RTS) at 66kV.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

RTS - CW	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	207	394	676	943	1270
Annual hours at risk (hrs)	39	64	96	122	151

RTS - NR	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	47	113	227	366	559
Annual hours at risk (hrs)	12	26	41	58	80

B - CW	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	265	463	739	988	1290
Annual hours at risk (hrs)	61	93	131	164	199

Network solutions to manage load at risk

- Load reduction involving transfer of load via 11kV links to adjacent stations.
- Uprate RTS-CW 66kV feeder exit element by the end of 2012 at an estimated cost of 200K
- Uprate RTS-NR 66kV feeder exit element by the end of 2012 at an estimated cost of 200K
- Establish a plant protection scheme at NR by the end of 2014 at an estimated cost of \$200K.
- Establish a plant protection scheme at CW by the end of 2014 at an estimated cost of \$200K
- Establish separate loop supply for NR by the end of 2017 at an estimated cost of \$9.0M.

Although the expected demand of the above lines over the next five years will exceed their corresponding line ratings, with the implementation of the above proposed network solutions to cover this shortfall, it is expected that all customers can be supplied following the outage of a major line during this planning period.

RTS-FR-MP-RTS 66KV SUBTRANSMISSION LINES

Supply points & line loading

The RTS-FR-MP subtransmission lines supply the FR (Flinders Ramsden) and MP (McIlwraith Place) zone substations fed from Richmond Terminal Station (RTS) at 66kV.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

RTS – FR1	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	185	318	531	828	1,221
Annual hours at risk (hrs)	107	145	191	248	309

RTS – FR2	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	44	102	216	394	650
Annual hours at risk (hrs)	28	51	86	126	179

RTS – FR3	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	28	73	166	319	544
Annual hours at risk (hrs)	20	39	70	108	155

Network solutions to manage load at risk

- Load reduction involving transfer of load via 11kV links to adjacent stations.
- Establish 11kV link between FR/MP to BQ to facilitate a permanent load transfer by the end of 2015 at an estimated cost of \$6.8M
- Establish 3rd transformer at BQ by the end of 2016 at an estimated cost of \$6.6M

The expected demand of the above lines over the next five years will exceed their corresponding line ratings even with the implementation of the above proposed network solutions to cover this shortfall, therefore it is expected that not all customers can be supplied following the outage of a major line during this planning period between 2012 and 2015.

RTS-R-PR-RTS 22KV SUBTRANSMISSION LOOPSupply points & line loading

The RTS-R-PR-SM-RTS subtransmission loop supplies the Richmond zone substation (R) and Prahran zone substation (PR). There are 3x22kV lines from RTS to R and 2x22kV lines from RTS to PR. R and PR is connected via a single R-PR 22kV line. The Cremorne Victorian Railway substation is also fed from R at 22kV.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

RTS – PR129	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	135	182	239	250	267

Annual hours at risk (hrs)	148	186	228	233	263
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RTS – PR130	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	96	116	139	167	199
Annual hours at risk (hrs)	113	129	148	170	193

R – PR127	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	247	356	490	717	1,021
Annual hours at risk (hrs)	246	314	399	565	785

RTS – R134	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	65	119	212	364	599
Annual hours at risk (hrs)	58	104	183	311	482

RTS – R135	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	1,679	2,464	3,443	4,547	5,820
Annual hours at risk (hrs)	1,160	1,527	1,918	2,307	2,637

RTS – R136	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	2,147	3,058	4,163	5,403	6,792
Annual hours at risk (hrs)	1,389	1,782	2,171	2,535	2,841

Network solutions to manage load at risk

- Load reduction involving transfer of load via 11kV links to adjacent stations.
- Reconfigure the 22kV subtransmission and zone substation arrangement to reduce overload.
- Establish a plant protection scheme at R by end of 2013 at an estimated cost of \$200K.
- Establish 11kV link between PR to BC to facilitate a permanent load transfer by the end of 2013 at an estimated cost of \$1.5M
- Establish 11kV link between R to TK to facilitate a permanent load transfer by the end of 2012 in conjunction with a customer connection application. This project is subject to customer acceptance prior to proceeding. Alternatively, establish 11kV link between R to TK to facilitate a permanent load transfer by the end of 2013 at an estimated cost of \$2.5M. This is not subject to customer acceptance.

Although the expected demand of the above lines over the next five years will exceed their corresponding line ratings, with the implementation of the above proposed network solutions to cover this shortfall, it is not expected that all customers can be supplied following the outage of a major line during 2012 and 2013.

SVTS-RD-EB-SVTS 66KV SHARED SUBTRANSMISSION LOOP*Supply points & line loading*

The SVTS-RD-EB-SVTS subtransmission lines supply the Riverdale (RD) and East Burwood (EB) zone substations fed from Springvale Terminal Station (SVTS) at 66kV. EB is a United Energy Distribution's zone substation.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

SVTS – RD	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	651	945	1,316	1,886	2,591
Annual hours at risk (hrs)	77	103	135	182	235

Network solutions to manage load at risk

- Load reduction involving transfer of load via 11kV links to adjacent stations (CitiPower actions).
- Load reduction involving transfer of load via 22kV links to adjacent stations (United Energy Distribution actions).
- Modify existing plant protection scheme at RD by end of 2013 at an estimated cost of \$100K
- Uprate SVTS – RD (13.8km) line section by the end of 2013 at an estimated cost of \$3.6M.

Although the expected demand of the above line over the next five years will exceed their corresponding line rating, with the implementation of the above proposed network solutions to cover this shortfall, it is expected that all customers can be supplied following the outage of a major line during this planning period.

Note: United Energy Distribution owns the SVTS-EB and EB-RD lines and, by agreement, will undertake the lead role to manage any load at risk of the SVTS-EB and EB-RD lines.

TSTS-L-Q-HB-TSTS 66KV SHARED SUBTRANSMISSION LOOP*Supply points & line loading*

The TSTS-L-Q-TSTS subtransmission lines supply the Balwyn (L), Kew (Q), and Heidelberg (HB) zone substations fed from Templestowe Terminal Station (TSTS) at 66kV. HB is an Alinta AE zone substation.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

TSTS – L	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	439	632	806	1,061	1,384
Annual hours at risk (hrs)	60	87	114	150	196

L – Q	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	292	436	587	819	1,119
Annual hours at risk (hrs)	86	125	171	234	308

Q – HB	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	49	98	142	200	266
Annual hours at risk (hrs)	15	25	32	39	47

Network solutions to manage load at risk

- Load reduction involving transfer of load via 11kV links to adjacent stations (CitiPower action).
- Modify existing plant protection scheme at L by end of 2013 at an estimated cost of \$100K
- Establish a 6 MVAR capacitor bank at L zone substation by the end of 2013 at an estimated cost of \$570K
- Establish a plant protection scheme at Q by end of 2013 at an estimated cost of \$100K.
- Establish a 6 MVAR capacitor bank at Q zone substation by the end of 2013 at an estimated cost of \$570K
- Uprate TSTS-L by the end of 2017 at an estimated cost \$2.7M

Although the expected demand of the above lines over the next five years will exceed their corresponding line ratings, with the implementation of the above proposed network solutions to cover this shortfall, it is expected that all customers can be supplied following the outage of a major line during this planning period.

Note: Alinta AE owns the TSTS-HB line and, by agreement, will undertake the lead role to manage any load at risk of the TSTS-HB line.

WMTS-DA 22KV SUBTRANSMISSION LOOP

Supply points & line loading

The WMTS-DA subtransmission lines supplies Docklands (DA) zone substation fed from West Melbourne Terminal Station (WMTS) at 22kV.

Magnitude and impact of loss of load

The table below provides more detailed data on energy at risk and hours at risk excluding any planned augmentation or operational response such as load transfers to mitigate the impact of an outage:

WMTS – DA213	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	507	1,304	2,875	6,410	11,861
Annual hours at risk (hrs)	243	531	1,171	2,242	3,339

WMTS – DA222	2012	2013	2014	2015	2016
Annual energy at risk (MWh)	553	1,331	2,875	6,227	11,566
Annual hours at risk (hrs)	260	540	1,171	2,179	3,241

Network solutions to manage load at risk

- Load reduction involving transfer of load via 11kV links to adjacent stations.
- Establish 11kV link between DA to WG to facilitate a permanent load transfer by the end of 2012. This project is subject to customer acceptance prior to proceeding. Alternatively, establish 11kV link between DA to WG to facilitate a permanent load transfer by the end of 2013 at an estimated cost of \$500K. This is not subject to customer acceptance.
- Convert WMTS-DA 22kV line to 66kV by the end of 2016 at an estimated cost of \$700K.

The expected demand of the above lines over the next five years will exceed their corresponding line ratings even with the implementation of the above proposed network solutions to cover this shortfall, therefore it is possible that not all customers can be supplied following the outage of a major line in the period between 2012 and 2013.

6. CBD SECURITY OF SUPPLY UPGRADE PLAN

Clause 3.5.3A of the Distribution Code requires CitiPower to outline the capital and other works connected with the security to supply objective:-

“3.5.3A In fulfilling the requirements of clause 3.5.1(c) (if applicable), the report must include the following information:

- (a) an outline of the capital and other works carried out in the preceding year in implementing the Melbourne ***CBD security of supply upgrade plan***,
- (b) an evaluation of whether the relevant security of supply objectives specified in the Melbourne ***CBD security of supply upgrade plan*** have been achieved in the preceding year; and
- (c) an outline of the capital and other works connected with the security of supply objectives proposed to be carried out in the following 5 years.”

6.1 CBD Security of Supply Upgrade Plan

In response to Parts (a) and (b) of Clause 3.5.3A, the following table is an outline of the capital and other works carried out in 2010 in implementing the Melbourne CBD security of supply upgrade plan. For completeness, it also lists related project works which, while not part of the scope of security works, are required as part of the overall network development scenario to enable the security upgrade works to be completed

Description of capital works	2011 Progress – Part (a)	Evaluation of 2011 against objectives – Part (b)
<i>Transmission, Capacity Related</i>		
Install 2 x 220/66kV 225MVA transformers	Planning permit for new option to develop BTS rejected by	Objectives remain.. BTS practical completion date has been delayed

(including 3x220kV switchgear and 17x66kV GIS double bus CBs)	Moreland Council in November 2011. An appeal to VCAT has been initiated.	to 2015 from 2012
<i>Distribution, Capacity Related</i>		
Install 2 x 66kV 120 MVA cables from BTS to BQ including protection works at both ends	Part completed installation of 1 x 66kV 120 MVA cable.	Objectives remain. Proceeding to revised targets.
Install 9 x 66kV CB's + isolators in double bus configuration – at BQ	Practical completion	Achieved completion targets.
Install 2 x 66/11kV 60MVA transformers + 11kV switchgear & secondary works – at BQ	Commissioned 1 x 66/11kV 60MVA transformers + 11kV switchgear & secondary works – at BQ	Work staged due to BTS planning permit issue. Achieved revised targets.
Station refurbishment costs for BQ including civil works for switch bay floors	Practical completion	Achieved targets.
<i>Distribution, Security Enhancement</i>		
BTS Connection CB and protection works	Planning permit for new option to develop BTS rejected by Moreland Council. An appeal to VCAT will be initiated.	Objectives remain. BTS practical completion date has been delayed to 2015 from 2012
Install 1 x 66kV 120MVA cables from BTS to VM including protection works at both ends	Part completed installation of 1 x 66kV 120 MVA cable.	Revised completion date due to BTS planning permit issue. Achieved revised targets.
Install 2 x 66kV 120MVA cables from BQ to VM including protection works at both ends	Commissioned 2 x 66kV cables.	Objectives remain. Achieved revised targets.
Replace 9 x 66kV isolators with 19 GIS CB's and isolators (double bus configuration) – including station refurbishment works at VM	Completed	Achieved revised targets.
Replace 7 x 66kV isolators with 7 GIS CB's + isolators (Allow room for ultimate 18 x 66kV GIS CB's + isolators) – including station refurbishment works at W	Function scope being finalised	Revised completion date due to BTS planning permit issue. Achieved revised targets.
Install 2 x 66kV 120MVA cables from BQ to W including protection works at both ends. Including minor works at substation WA, FR and MP	Revised estimates received from supplier	Revised completion date due to BTS planning permit issue. Achieved revised targets.
Redirect VM – W 66kV cable to run from VM to WA	Revised estimates received from supplier	Revised completion date due to BTS planning permit issue. Achieved revised targets.

In response to part (c) of Clause 3.5.3A, the following table presents the project timeline for the CBD security of supply project. For completeness, it also lists related project works which, while not part of the scope of security works, are required as part of the overall network development scenario to enable the security upgrade works to be completed.

Description of capital works	2009	2010	2011	2012	2013	2014	2015
<i>Transmission, Capacity Related</i>							
Install 2 x 220/66kV 225MVA transformers (including 3x220kV switchgear and 17x66kV GIS double bus CBs)	x	x	x	x	x	x	x
<i>Distribution, Capacity Related</i>							
Install 2 x 66kV 120 MVA cables from BTS to BQ including protection works at both ends	x	x	x	x			
Install 9 x 66kV CB's + isolators in double bus configuration – at BQ		x	x	x			
Install 2 x 66/11kV 60MVA transformers + 11kV switchgear & secondary works – at BQ		x	x	x			
Station refurbishment costs for BQ including civil works for switch bay floors	x	x	x	x			
<i>Distribution, Security Enhancement</i>							
BTS Connection CB and protection works	x	x	x	x	x	x	
Install 1 x 66kV 120MVA cables from BTS to VM including protection works at both ends	x	x	x	x	x	x	
Install 2 x 66kV 120MVA cables from BQ to VM including protection works at both ends	x	x	x	x	x	x	
Replace 9 x 66kV isolators with 19 GIS CB's and isolators (double bus configuration) – including station refurbishment works at VM	x	x	x				
Replace 7 x 66kV isolators with 7 GIS CB's + isolators (Allow room for ultimate 18 x 66kV GIS CB's + isolators) – including station refurbishment works at W			x	x	x	x	x
Install 2 x 66kV 120MVA cables from BQ to W including protection works at both ends. Including minor works at substation WA, FR and MP				x	x	x	x
Redirect VM – W 66kV cable to run from VM to WA				x	x	x	x

x – works being carried out

The 66kV bus-tie switches in FR and MP have been replaced by equivalent 11kV load transfer capability between FR, MP and BQ.

6.2 Additional Distribution Level Works to deliver N-1 secure

CitiPower has highlighted to the ESC and the AER that a final component of the security of supply enhancement strategy is the establishment of additional 11kV feeder transfer capability and distribution remote switching at JA, MP, WA and LQ. CitiPower stated that these works can be done in concert with demand growth projects on feeders from these stations at the completion of the project works.

Appendix 2 – Summary of Zone Substation Capacities and Load Forecasts 2012-2016 (Excluding Planned Response)

Zone substation capacity						←---ACTUAL FORECAST---→																											
ZONE SUBSTATION	No. of Transformers	NAME-PLATE		N-1 CYCLIC		2010 Winter MD		2011 Summer MD		2011 Winter MD		2012 Summer MD		2012 Winter MD		2013 Summer MD		2013 Winter MD		2014 Summer MD		2014 Winter MD		2015 Summer MD		2015 Winter MD		2016 Summer MD		2016 Winter MD			
		NON-FIRM	FIRM	SCR	WCR	MVA	MVA above WCR	MVA	MVA above SCR	MVA	MVA above WCR	MVA	MVA above SCR	MVA	MVA above WCR	MVA	MVA above SCR	MVA	MVA above WCR	MVA	MVA above SCR	MVA	MVA above WCR	MVA	MVA above SCR	MVA	MVA above WCR	MVA	MVA above SCR	MVA	MVA above WCR		
1	AP (NOAC on Tx3)	3	60.0	30.0	61.6	74.7	52.2	---	62.7	1.1	53.8	---	61.4	---	55.3	---	63.3	1.7	52.2	---	64.9	3.3	59.0	---	66.3	4.7	60.5	---	62.7	1.1	62.0	---	
2	AR	2	60.0	30.0	32.9	36.6	31.8	---	39.4	6.5	34.2	---	38.3	---	34.6	---	38.7	5.8	35.0	---	39.1	6.2	35.4	---	39.6	6.7	35.8	---	40.0	7.1	36.2	---	
3	B	2	54.0	27.0	29.0	32.6	25.1	---	37.6	8.6	26.3	---	36.8	---	27.0	---	37.5	8.5	27.6	---	38.2	9.2	28.2	---	38.9	9.9	28.8	---	39.6	10.6	29.4	---	
4	BC	2	60.0	30.0	32.1	41.6	26.3	---	29.8	---	28.5	---	28.4	---	28.8	---	28.8	---	29.1	---	29.2	---	29.4	---	29.6	---	29.7	---	29.9	---	30.0	---	
5	BK (NOAC on Tx2)	3	20.0	20.0	27.2	28.6	14.4	---	14.7	---	14.5	---	14.6	---	14.8	---	15.0	---	15.2	---	15.4	---	15.6	---	15.9	---	15.9	---	16.3	---	16.3	---	
6	BBSQ	3	30.0	20.0	25.4	28.4	36.1	7.7	46.6	21.2	36.1	7.7	27.5	2.1	27.3	---	29.2	3.8	28.4	0.0	30.3	4.9	29.4	1.0	31.3	5.9	30.5	2.1	32.4	7.0	31.5	3.1	
	(N) BQ	2			60.0	65.0	0.0	---	0.0	---	0.0	---	40.5	---	32.3	---	40.9	---	32.8	---	41.9	---	33.4	---	43.9	---	35.5	---	44.9	---	36.2	---	
7	C	3	15.0	15.0	17.0	17.0	12.4	---	12.2	---	12.8	---	12.3	---	13.4	---	12.8	---	13.7	---	13.2	---	14.0	---	13.5	---	14.3	---	13.9	---	14.6	---	
8	CL	3	87.0	57.0	65.8	71.0	38.3	---	71.3	5.5	42.7	---	69.8	4.0	44.6	---	72.1	6.3	46.5	---	74.5	8.7	48.4	---	76.8	11.0	50.4	---	79.1	13.3	52.3	---	
9	CW	2	54.0	27.0	33.4	37.3	26.2	---	29.3	---	28.7	---	31.0	---	29.5	---	31.9	---	30.2	---	32.7	---	30.9	---	33.6	0.2	31.7	---	34.4	1.0	32.4	---	
10	DA	3	40.5	27.0	29.2	32.6	27.5	---	33.6	4.4	30.7	---	37.7	8.5	32.5	---	40.5	11.3	35.0	2.4	43.2	14.0	37.5	4.9	46.0	16.8	40.0	7.4	48.8	19.6	42.5	9.9	
11	E (NOAC on BT)	3	43.5	23.5	21.8	24.2	6.5	---	7.4	---	6.8	---	7.7	---	7.0	---	7.9	---	7.1	---	8.1	---	7.3	---	8.2	---	7.5	---	8.4	---	7.6	---	
12	F (NOAC on Tx1)	3	20.0	20.0	24.1	28.5	16.2	---	15.2	---	17.2	---	15.0	---	17.6	---	15.4	---	18.0	---	15.9	---	18.4	---	16.3	---	18.8	---	16.7	---	19.2	---	
13	FB	3	90.0	60.0	63.7	69.5	22.3	---	25.3	---	23.6	---	26.9	---	24.4	---	28.3	---	26.1	---	31.5	---	28.8	---	32.6	---	30.1	---	34.0	---	31.5	---	
14	FR (NOAC on BT)	3	90.0	60.0	61.4	73.2	44.6	---	63.6	2.2	48.3	---	61.9	0.5	50.7	---	63.3	1.9	52.0	---	64.7	3.3	53.3	---	66.1	4.7	54.6	---	67.5	6.1	55.9	---	
15	J (NOAC on Tx1)	4	30.0	20.0	38.4	42.2	14.4	---	20.6	---	16.6	---	16.4	---	12.4	---	17.0	---	13.0	---	17.6	---	13.6	---	18.3	---	14.2	---	18.9	---	14.8	---	
16	JA	3	165.0	110.0	128.0	127.4	64.5	---	107.2	---	76.7	---	130.1	2.1	97.0	---	136.8	8.8	103.0	---	144.6	16.6	109.5	---	153.4	25.4	117.2	---	161.9	33.9	124.3	---	
17	L	2	60.0	30.0	32.1	40.6	34.7	---	38.7	6.6	34.1	---	41.6	9.5	34.7	---	43.5	11.4	35.3	---	44.2	12.1	35.8	---	44.8	12.7	36.4	---	45.5	13.4	37.0	---	
18	LQ (NOAC on Tx1)	3	120.0	120.0	131.8	142.8	77.7	---	110.6	---	86.8	---	118.6	---	89.0	---	121.4	---	91.1	---	126.1	---	97.0	---	129.9	---	99.3	---	132.8	1.0	101.6	---	
19	LS	3	30.0	20.0	24.2	26.8	21.0	---	30.5	6.3	21.4	---	26.5	2.3	22.3	---	27.6	3.4	23.3	---	28.7	4.5	24.3	---	29.8	5.6	25.3	---	30.9	6.7	26.3	---	
20	MG (NOAC on Tx3)	3	57.0	57.0	61.7	63.9	33.4	---	45.2	---	28.8	---	46.1	---	31.3	---	49.1	---	34.4	---	52.2	---	37.1	---	55.0	---	39.7	---	57.8	---	42.4	---	
21	MP	3	165.0	110.0	124.0	123.8	91.1	---	127.3	3.3	97.0	---	122.9	---	100.1	---	125.4	1.4	102.4	---	127.9	3.9	104.7	---	130.3	6.3	107.0	---	132.7	8.7	109.4	---	
22	NC	2	60.0	30.0	32.4	41.0	28.2	---	27.9	---	30.6	---	30.7	---	31.1	---	31.3	---	31.6	---	31.9	---	32.2	---	32.5	0.1	32.7	---	33.1	0.7	33.3	---	
23	NR (NOAC on Tx2)	3	56.0	56.0	56.1	61.2	42.7	---	60.0	3.9	44.9	---	58.2	2.1	46.8	---	59.8	3.7	48.6	---	62.0	5.9	49.8	---	63.6	7.5	51.1	---	64.9	8.8	52.2	---	
24	PM (NOAC on Tx1)	3	40.5	27.0	28.0	29.2	13.0	---	17.1	---	13.6	---	17.3	---	14.5	---	18.2	---	15.4	---	19.2	---	16.3	---	20.2	---	17.2	---	21.2	---	18.2	---	
25	PR (NOAC on Tx3)	3	36.9	23.4	30.0	33.0	23.0	---	24.9	---	22.6	---	31.5	1.5	24.0	---	32.2	2.2	24.6	---	33.0	3.0	25.2	---	33.7	3.7	25.9	---	34.5	4.5	26.5	---	
26	Q	2	60.0	30.0	30.7	35.8	34.5	---	40.0	9.3	36.2	0.4	40.8	10.1	37.2	1.4	41.8	11.1	37.9	2.1	42.6	11.9	38.7	2.9	43.5	12.8	39.4	3.6	44.3	13.6	40.2	4.4	
27	R	3	42.0	28.0	31.4	36.2	25.8	---	36.3	4.9	28.7	---	37.3	5.9	30.5	---	38.8	7.4	31.9	---	40.2	8.8	33.2	---	41.6	10.2	34.5	---	43.1	11.7	35.7	---	
28	RD	2	60.0	30.0	30.6	36.0	32.1	---	40.1	9.5	32.2	---	44.0	13.4	32.8	---	44.5	13.9	33.1	---	44.8	14.2	33.4	---	45.1	14.5	33.6	---	45.4	14.8	33.9	---	
29	RP	3	40.5	27.0	18.7	20.2	9.5	---	15.0	---	10.0	---	14.1	---	10.2	---	14.3	---	10.4	---	14.6	---	10.6	---	14.8	---	10.8	---	15.1	---	11.0	---	
30	SK (NOAC on Tx3)	3	57.0	57.0	62.7	73.6	42.4	---	63.0	0.3	47.5	---	66.4	3.7	48.9	---	68.1	5.4	50.3	---	69.7	7.0	51.8	---	71.3	8.6	53.2	---	73.0	10.3	54.6	---	
31	SB	3	27.0	27.0	68.3	72.8	0.0	---	35.2	---	27.9	---	28.5	---	30.7	---	33.1	---	33.0	---	34.4	---	33.8	---	35.2	---	34.6	---	36.1	---	35.4	---	
32	SO	3	87.0	57.0	63.7	69.6	50.7	---	52.2	---	33.0	---	51.7	---	34.7	---	53.5	---	36.5	---	55.3	---	38.3	---	57.1	---	40.1	---	58.9	---	41.9	---	
33	TK	2	87.0	57.0	50.8	66.9	31.7	---	46.6	---	36.9	---	48.2	---	38.5	---	49.8	---	40.2	---	51.1	0.3	41.1	---	52.1	1.3	41.9	---	53.0	2.2	42.7	---	
34	TP	2	20.0	10.0	11.6	12.2	8.6	---	10.6	---	9.0	---	6.3	---	5.4	---	6.6	---	5.6	---	6.8	---	5.8	---	7.0	---	6.0	---	7.2	---	6.2	---	
35	VM	3	84.0	54.0	63.2	69.0	61.4	---	76.9	13.7	67.3	---	57.1	---	47.7	---	61.0	---	51.1	---	64.6	1.4	54.6	---	68.5	5.3	58.4	---	72.5	9.3	62.2	---	
36	WA	3	84.0	54.0	67.0	72.3	41.7	---	62.3	---	46.8	---	69.0	2.0	49.4	---	71.0	4.0	51.1	---	73.0	6.0	52.8	---	75.0	8.0	54.6	---	77.1	10.1	56.4	---	
37	WB (NOAC on BT)	2	60.0	30.0	26.4	31.6	21.4	---	28.4	2.0	26.0	---	29.1	2.7	26.9	---	29.8	3.4	27.6	---	30.5	4.1	28.2	---	31.3	4.9	28.9	---	32.0	5.6	29.5	---	
38	WG	3	81.0	54.0	71.7	71.7	32.0	---	39.6	---	29.5	---	39.0	---	37.0	---	44.3	---	44.1	---	52.1	---	48.6	---	54.7	---	50.7	---	56.8	---	52.9	---	

Appendix 3 – Summary of Subtransmission Lines Capacities and Load Forecasts 2012-2016 (Excluding Planned Response)

Sub Transmission Line	Capacity of Line (Amps)		Forecast Maximum Summer Demand (Amps)**Under outage of one relevant line (N-1)																			
	Summer	Winter	2012 Summer		2012 Winter		2013 Summer		2013 Winter		2014 Summer		2014 Winter		2015 Summer		2015 Winter		2016 Summer		2016 Winter	
			MD (Amps)	% Above Capacity	MD (Amps)	% Above Capacity	MD (Amps)	% Above Capacity	MD (Amps)	% Above Capacity	MD (Amps)	% Above Capacity	MD (Amps)	% Above Capacity	MD (Amps)	% Above Capacity	MD (Amps)	% Above Capacity	MD (Amps)	% Above Capacity	MD (Amps)	% Above Capacity
BTS 22kV																						
BTS-BK185	275	275	MD below line rating																			
BTS-BK187	270	270	MD below line rating																			
BTS-BK194	270	270	MD below line rating																			
BTS-C186	260	295	MD below line rating																			
BTS-C191	260	295	MD below line rating																			
BTS-C196	260	295	MD below line rating																			
BTS-F179	314	330	MD below line rating																			
BTS-F182	314	330	MD below line rating																			
BTS-F189	370	388	MD below line rating																			
FBTS 66kV																						
FBTS-AP	1,025	1,105	MD below line rating																			
FBTS-MG	1,025	1,100	MD below line rating																			
AP-MG	790	845	MD below line rating																			
FBTS-E	515	690	MD below line rating																			
FBTS-PM	515	760	MD below line rating																			
E-PM	515	760	MD below line rating																			
FBTS-FB	1,025	1,105	MD below line rating																			
FBTS-WG	1,025	1,105	MD below line rating																			
FB-WG	690	740	MD below line rating																			
FBTS-P107 (SO#1 line tee-off to SM)	880	925	MD below line rating																			
FBTS-SO 2	800	925	MD below line rating																			
P107-SO (from SO#1 line tee-off to SO)	800	1,000	MD below line rating																			
RTS 66kV																						
RTS-AR	890	955	1074	20.7	MD below line rating	1101	23.7	MD below line rating	1128	26.8	MD below line rating	1148	29.0	MD below line rating	1169	31.3	969	1.4				
RTS-TK	880	955	1014	15.3	MD below line rating	1038	18.0	MD below line rating	1062	20.7	MD below line rating	1075	22.2	MD below line rating	1088	23.6	MD below line rating					
BC-AR	610	610	725	18.8	MD below line rating	746	22.3	MD below line rating	767	25.8	MD below line rating	783	28.3	MD below line rating	798	30.8	MD below line rating					
BC-TK	790	820	MD below line rating																			
RTS-CL	1,025	1,060	MD below line rating																			
CL-K	730	925	MD below line rating																			
RTS-CW	1,025	1,080	1,181	15.2	MD below line rating	1,223	19.3	MD below line rating	1,265	23.4	MD below line rating	1,295	26.3	MD below line rating	1,324	29.2	MD below line rating					
RTS-NR	1,025	1,120	1,112	8.5	MD below line rating	1,148	12.0	MD below line rating	1,184	15.5	MD below line rating	1,214	18.5	MD below line rating	1,245	21.5	MD below line rating					
B-CW	750	800	892	18.9	MD below line rating	923	23.1	MD below line rating	955	27.3	MD below line rating	977	30.3	MD below line rating	999	33.2	MD below line rating					
B-NR	790	845	MD below line rating																			
RTS-SK	785	815	MD below line rating							786	0.1	MD below line rating	0	--	MD below line rating	829	5.6	MD below line rating				
RTS-FR1	720	765	790	9.7	MD below line rating	811	12.7	MD below line rating	833	15.7	MD below line rating	854	18.6	MD below line rating	875	21.6	MD below line rating					
RTS-FR2	720	765	766	6.3	MD below line rating	786	9.2	MD below line rating	807	12.0	MD below line rating	827	14.8	MD below line rating	847	17.6	MD below line rating					
RTS-FR3	720	765	759	5.4	MD below line rating	779	8.2	MD below line rating	800	11.1	MD below line rating	820	13.9	MD below line rating	840	16.6	MD below line rating					
FR1-MP1	670	740	MD below line rating																			
FR2-MP2	720	760	MD below line rating																			
FR3-W3	715	770	MD below line rating																			
W3-MP3	670	760	MD below line rating																			

RTS 22kV																									
RTS-PR129	341	358	438	28.3	MD below line rating	448	31.5	MD below line rating	459	34.7	341	--	461	35.1	361	0.9	462	35.5	382	6.7					
RTS-PR130	341	358	426	24.9	MD below line rating	432	26.6	MD below line rating	438	28.3	320	--	444	30.2	352	--	450	32.0	384	7.2					
R-PR127	279	306	380	36.4	MD below line rating	395	41.6	MD below line rating	409	46.8	MD below line rating	429	53.7	MD below line rating	448	60.7	MD below line rating								
RTS-R134	522	494	613	17.5	536	8.4	635	21.7	554	12.0	657	25.8	572	15.7	680	30.3	587	18.9	703	34.7	603	22.1			
RTS-R135	432	448	640	48.3	559	24.8	663	53.5	578	29.0	686	58.7	597	33.2	710	64.3	613	36.9	734	69.9	629	40.5			
RTS-R136	432	448	654	51.4	572	27.6	677	56.8	590	31.8	700	62.1	609	36.0	725	67.8	626	39.7	749	73.4	643	43.4			
RTS-RP123	300	300	<-----MD below line rating----->																						
RTS-RP124	300	300	<-----MD below line rating----->																						
RTS-RP125	240	265	<-----MD below line rating----->																						
WMTS 66V																									
WMTS-JA1	1,270	1,340	<-----MD below line rating----->												1,296	2.1	MD below line rating	1,376	8.4	MD below line rating					
WMTS-JA3	1,005	1,060	1,009	0.4	MD below line rating	1,055	5.0	MD below line rating	1,101	9.5	MD below line rating	1,161	15.6	1,062	0.2	1,222	21.6	1,137	7.3						
WMTS-VM 1	1,295	1,380	<-----MD below line rating----->																						
WMTS-VM 2	1,220	1,389	<-----MD below line rating----->																						
WMTS-VM 3	1,215	1,305	<-----MD below line rating----->			1,248	2.7	MD below line rating	1,293	6.4	MD below line rating	1,355	11.5	MD below line rating	1,418	16.7	MD below line rating								
VM1-LQ1	735	744	<-----MD below line rating----->																						
VM3-LQ3	735	744	<-----MD below line rating----->																						
VM2-JA4	800	800	<-----MD below line rating----->																						
JA4-LQ2	810	880	<-----MD below line rating----->																						
JA2-W2	1,054	1,120	<-----MD below line rating----->																						
VM1-WA1	330	350	<-----MD below line rating----->																						
VM2-WA2	330	350	<-----MD below line rating----->			338	2.4	MD below line rating	348	5.6	MD below line rating	356	8.0	MD below line rating	364	10.5	MD below line rating								
VM3-W1	330	350	336	1.7	MD below line rating	346	4.9	MD below line rating	356	8.0	MD below line rating	367	11.1	MD below line rating	377	14.3	MD below line rating								
W1-WA3	330	350	336	1.7	MD below line rating	346	4.9	MD below line rating	356	8.0	MD below line rating	367	11.1	MD below line rating	377	14.3	MD below line rating								
WMTS-NC	545	635	<-----MD below line rating----->												547	0.4	MD below line rating								
WMTS-WB	480	480	501	4.3	487	1.5	510	6.3	505	5.3	520	8.3	523	9.1	531	10.6	537	11.9	542	12.8	551	14.7			
NC-WB	430	770	<-----MD below line rating----->																						
WMTS 22V																									
WMTS-BS216	575	695	<-----MD below line rating----->												585	1.8	MD below line rating	623	8.3	MD below line rating					
WMTS-BS218	575	695	<-----MD below line rating----->												579	0.7	MD below line rating	584	1.6	MD below line rating	589	2.5	MD below line rating		
WMTS-DA213	800	850	1,050	31.3	880	3.5	1,139	42.4	880	3.5	1,228	53.5	880	3.5	1,324	65.4	880	3.5	1,419	77.4	880	3.5			
WMTS-DA222	800	850	1,058	32.3	885	4.1	1,143	42.9	885	4.1	1,228	53.5	885	4.1	1,317	64.6	885	4.1	1,406	75.8	885	4.1			
WMTS-J220	650	700	<-----MD below line rating----->																						
WMTS-LS214	690	700	<-----MD below line rating----->																						
WMTS-LS226	700	700	<-----MD below line rating----->																						
BS-J324	621	700	<-----MD below line rating----->																						
LS-J325	560	680	<-----MD below line rating----->																						
TSTS 66kV																									
TSTS-L	815	850	1,056	29.6	897	5.6	1,094	34.3	919	8.1	1,117	37.1	940	10.6	1,147	40.7	961	13.1	1,176	44.2	982	15.6			
HB-Q	615	815	826	34.3	MD below line rating	859	39.7	MD below line rating	881	43.2	MD below line rating	904	47.1	MD below line rating	928	51.0	MD below line rating								
Q-L	510	510	657	28.8	569	11.6	678	32.9	584	14.5	690	35.2	599	17.4	708	38.8	613	20.2	727	42.5	627	22.9			
SVTS 66kV																									
SVTS-RD	700	850	959	37.0	MD below line rating	1,001	43.0	MD below line rating	1,043	49.0	MD below line rating	1,094	56.3	MD below line rating	1,145	63.6	MD below line rating								

Appendix 4 – Summary of Zone Substation and Subtransmission Line Major Project Augmentations for 2012-2016 period

Zone Sub	Major Project Augmentations	Indicative Cost (\$m)				
		2012	2013	2014	2015	2016
B	Establish 3rd transformer at B				0.2	2.3
DA	Establish a plant protection scheme at DA	0.2				
	Establish 11kV link between DA to WG to facilitate a permanent load transfer		0.5			
	Establish DA zone substation into a 66kV substation		0.2	4.6	8.8	2.4
L	Establish a 6 MVAR capacitor bank at L zone substation	0.3	0.3			
LS	Establish 11kV link between LS and VM to facilitate a permanent load					0.1
NR	Establish normally open-auto close scheme on bus tie CB		0.2			
Q	Establish a 6 MVAR capacitor bank at Q zone substation	0.3	0.3			
R	Establish 11kV link between R to TK to facilitate a permanent load transfer		2.5			
SK	Establish normally open-auto close scheme on bus tie CB		0.2			
Subtransmission Loop	Major Project Augmentations	Indicative Cost (\$m)				
		2012	2013	2014	2015	2016
RTS-TK-BC-AR-RTS	Uprate/Reconductor RTS-TK 66kV line					0.9
	Uprate/Reconductor RTS-AR 66kV line					0.5
	Establish a plant protection scheme at AR and TK		0.8			0.4
RTS-NR-B-CW-RTS	Establish separate loop for NR				0.5	2.7
	Uprate RTS-CW and RTS-NR exit elements	0.4				
	Establish plant protection scheme at CW and NR		0.1	0.3		
RTS-FR-MP-RTS	Establish 11kV link between FR/MP to BQ to facilitate a permanent load transfer			0.5	6.3	
	Establish 3rd transformer at BQ		1.2	2.5	1.9	1.0
RTS-R-PR-RTS	Establish a plant protection scheme at R		0.2			
	Establish 11kV link between PR and BC to facilitate a permanent load transfer		1.5			
	Establish 11kV link between R to TK to facilitate a permanent load transfer		2.5			
SVTS-RD-EB-SVTS	Modify existing plant protection scheme at RD		0.1			
	Reconductor SVTS – RD line section	1.0	2.6			
TSTS-L-Q-HB-TSTS	Establish a plant protection scheme at Q and modify scheme at L		0.3			
	Establish 6MVAR capacitor banks each at L and Q	0.6	0.6			
	Uprate TSTS-L 66kV line					1.0
WMTS-DA	Upgrade WMTS – DA to 66kV				0.1	0.6
	Establish 11kV link between DA to WG to facilitate a permanent load transfer		0.5			

Glossary of Station Name Abbreviations and Terms

Abbreviation	CitiPower Zone Substation	Abbreviation	CitiPower Zone Substation
AP	Albert Park	MG	Montague
AR	Armadale	MP	McIllwraith Place
B	Collingwood	NC	Northcote
BC	Balaclava	NR	Nth Richmond
BK	Brunswick	PM	Port Melbourne
BSBQ	Bouverie/Queen	PR	Prahran
C	Brunswick	Q	Kew
CL	Camberwell	R	Richmond
CW	Collingwood	RD	Riversdale
DA	Dock Area	RP	Russell Place
E	Fishermans Bend	SK	St Kilda
F	Fitzroy	SM	South Melbourne
FB	Fishermans Bend	SO	South Melbourne
FR	Flinders/Ramsden	TK	Toorak
J	Spencer Street	TP	Tavistock Place
JA	Little Bourke Street	VM	Victoria Market
L	Deepline	W(switching station only)	Waratah Place
LQ	Little Queen	WA	Celestial Avenue
LS	Laurens Street	WB	West Brunswick
		WG	Westgate
NT	Newport (Jemena Asset)		

Abbreviation	Terminal Station (SPI PowerNet Asset)	Abbreviation	Terminal Station (SPI PowerNet Asset)
BTS	Brunswick	SVTS	Springvale
BLTS	Brooklyn	TSTS	Templestowe
FBTS	Fishermans Bend	WMTS	West Melbourne
RTS	Richmond		

Other common terms used in this document

kV	kilo volt
Amps	ampere
MW	mega watt
MWhr	mega watt hour
MVA	mega volt ampere