DISTRIBUTION SYSTEM PLANNING REPORT

Produced by

Powercor Australia Limited

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DISTRIBUTION SYSTEM PLANNING REPORT

POWERCOR AUSTRALIA LIMITED

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1 INTRODUCTION AND BACKGROUND

1.1 Purpose of this paper

This paper sets out the subtransmission asset planning report, prepared by the Victorian electricity distribution business Powercor Australia Limited, in accordance with the requirements of its Distribution Licence and the Electricity Distribution Code.

This paper is to provide preliminary information to ensure transparency of the network planning process and provide opportunity of non-network solutions to network constraints resulting from customer demand and load growth.

The assessment presented in this report is not a detailed planning analysis but a high-level description of the expected balance between capacity and demand at each zone substation and on each subtransmission line.

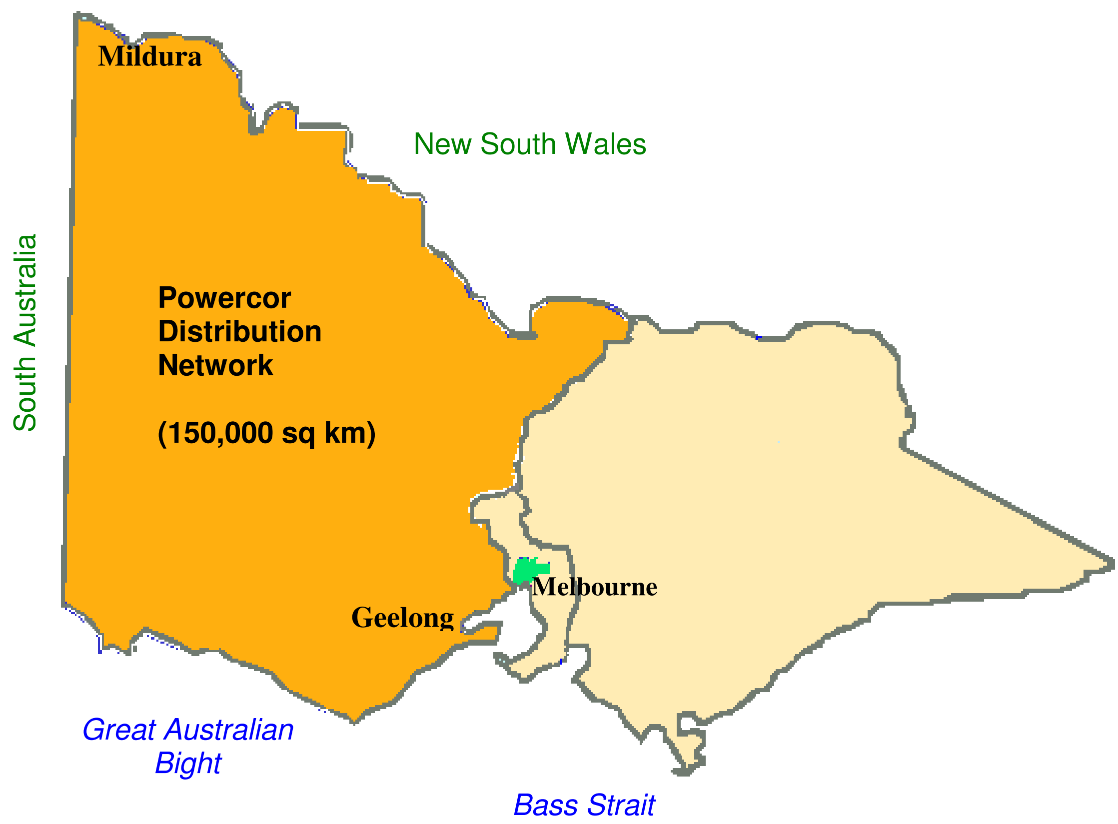
Data presented in this report may indicate an emerging constraint. Therefore, this report provides a means of identifying those subtransmission assets where more detailed analysis of risks and options for remedial action are required. This document also contains certain predictions and statements that reflect assumptions concerning specific area localised demand growth proposals, economic scenarios and historical load growth actuals and trends. The information presented provides opportunities to prospective proponents of alternatives to network augmentations at zone substations 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 end-customers.

Parties seeking further information about these potential opportunities, or any other matter contained in this report should contact:

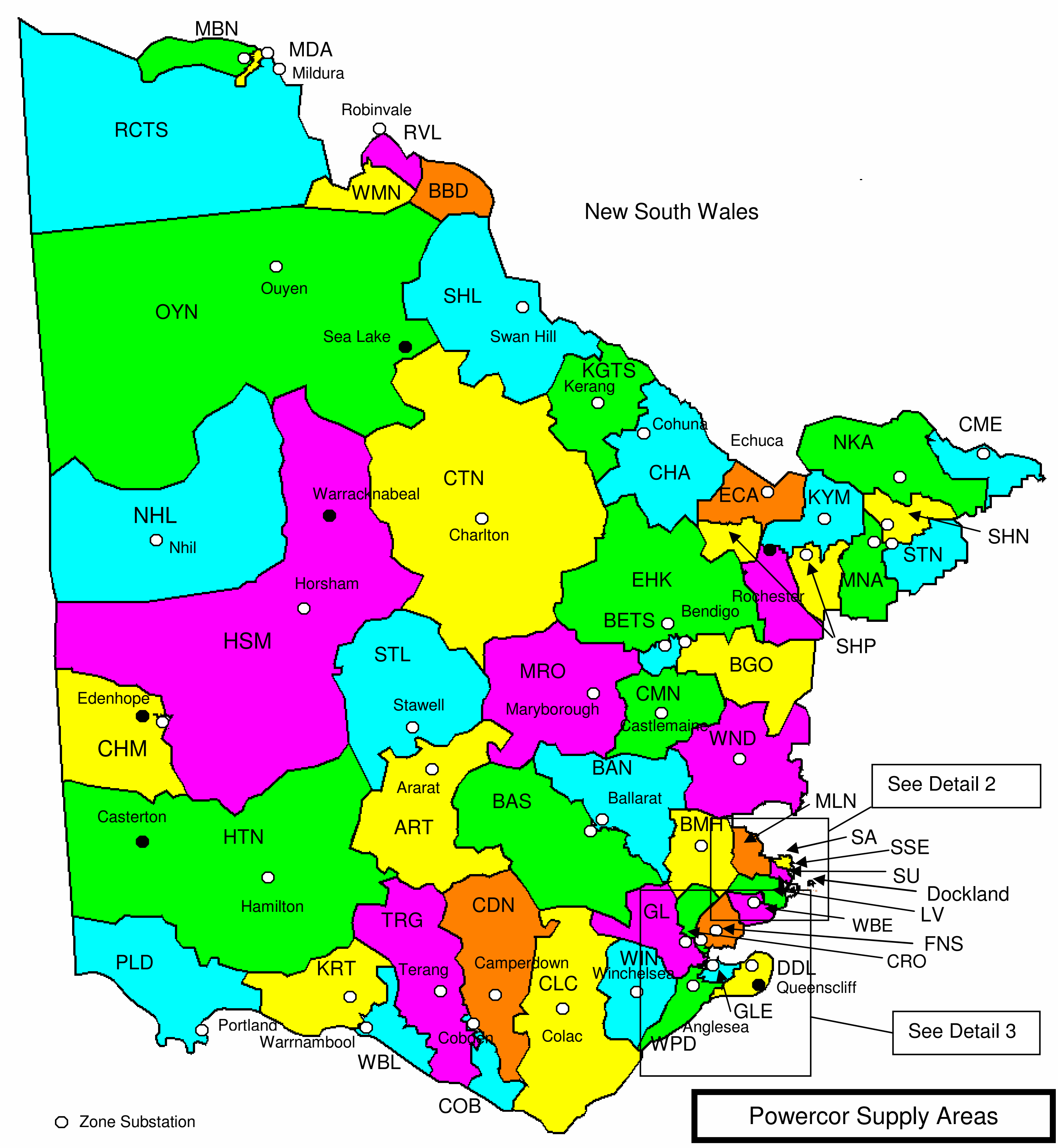
- Neil Gascoigne, System Planning & Secondary Systems Manager, Citipower/Powercor Australia, phone (03) 9683 4472.

The following page provides a map highlighting the location of the electricity distribution area supplied by Powercor Australia. This is followed by a map which illustrates the location of the Powercor zone substations in more detail and the area normally supplied by each individual zone substation.

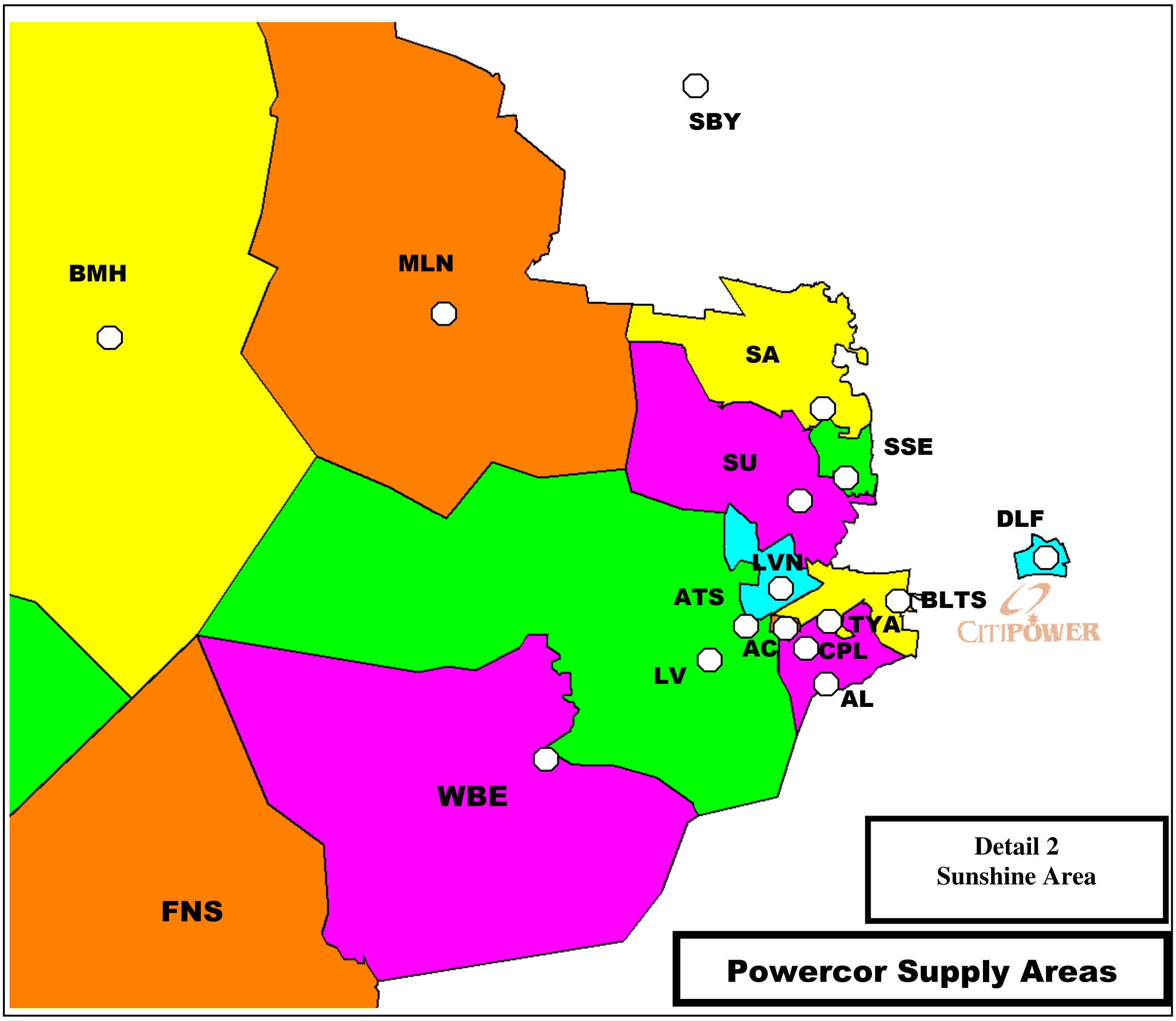
Powercor Australia Limited - Distribution Area



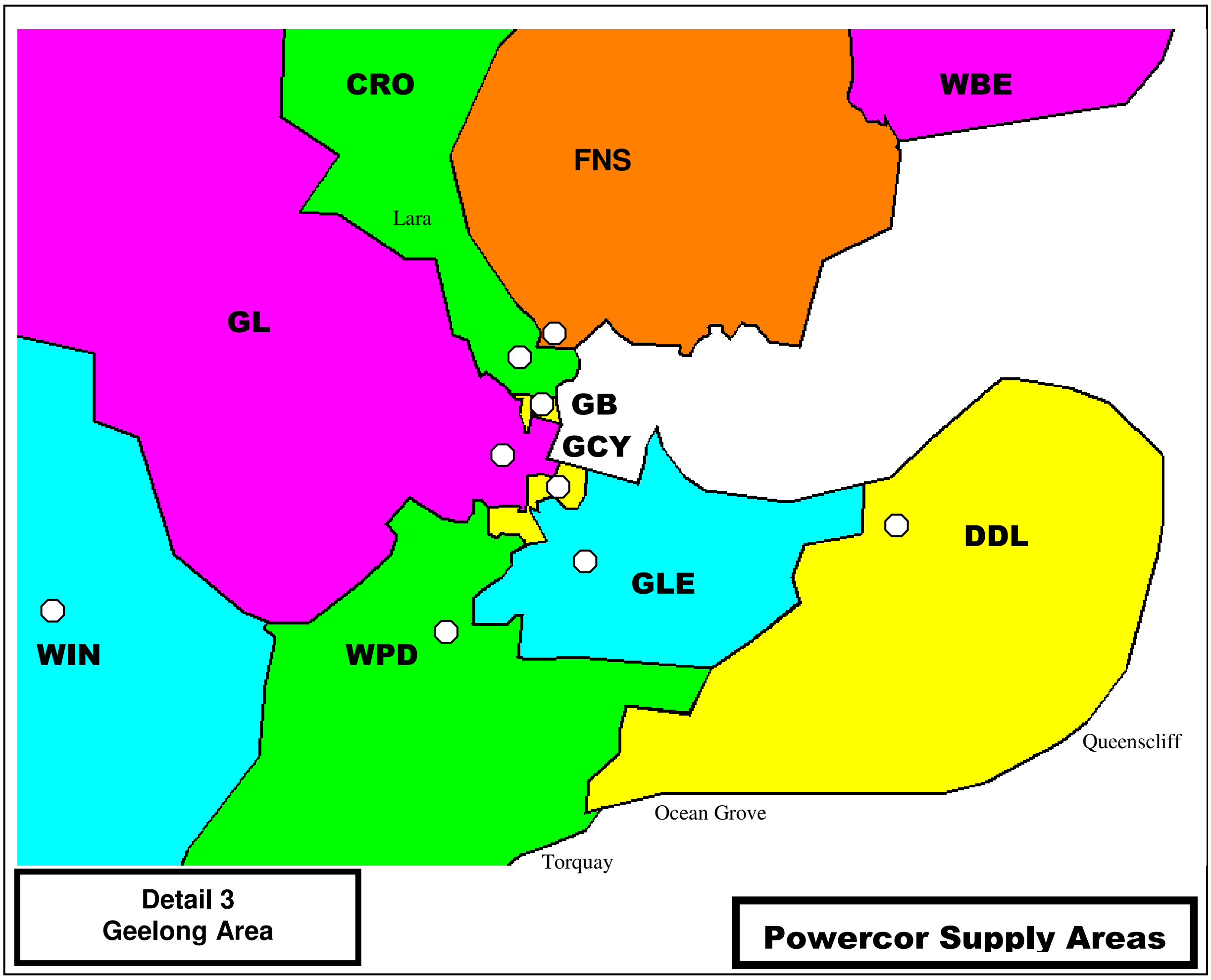
Powercor Zone Substation Areas



Powercor Zone Substation Area Detail 2



Powercor Zone Substation Area Detail 3



1.2 Distribution system planning

Powercor Australia Ltd is the largest distribution business in Victoria supplying electricity customers in the western segment of Victoria. Powercor has the responsibility for planning and directing the augmentation of the connection asset facilities connecting to the transmission system as well as owning, operating and planning of its assets that supply its network customers.

The distribution assets for which Powercor has planning responsibility form part of the Victorian Electricity System, shown diagrammatically in Figure 1.

Powercor's subtransmission assets (zone substations and subtransmission lines) are those parts of the distribution system which are dedicated to the connection of the distribution network to the transmission network. It enables the connection of medium sized generation or major customer(s) at a single point within the electrical system.

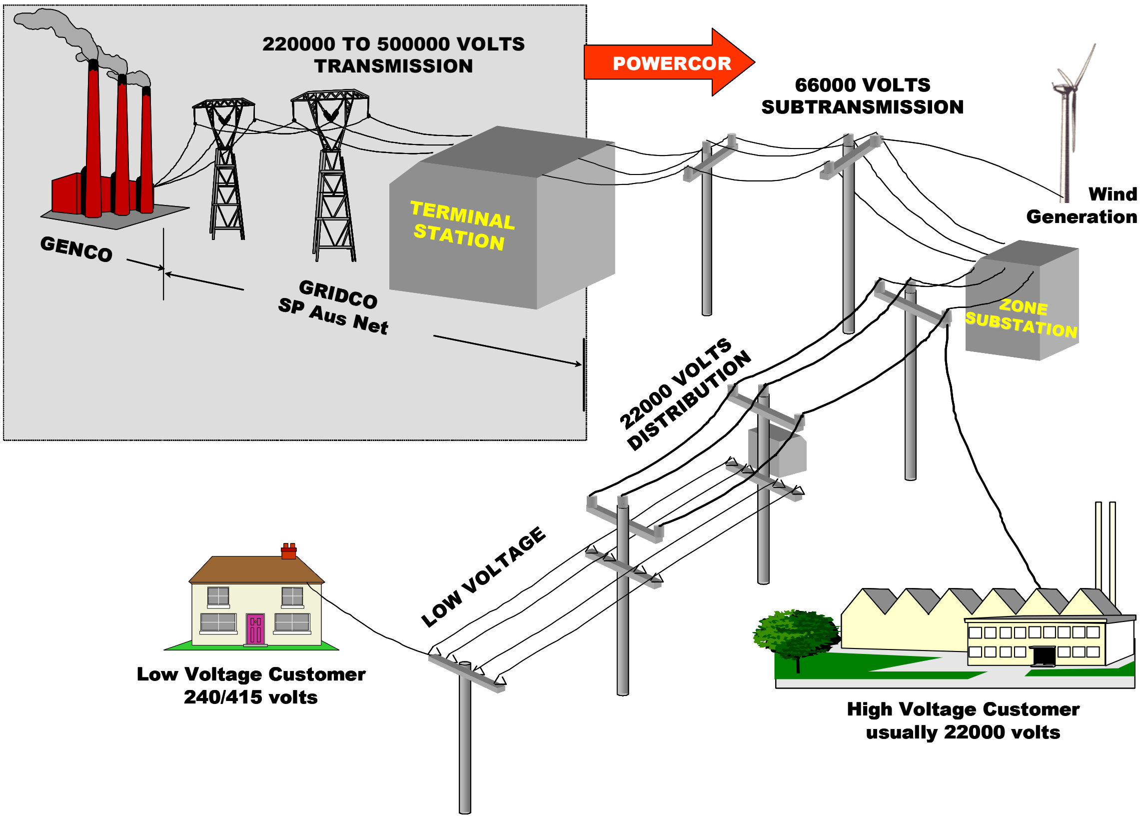


Figure 1: Powercor network assets in relation to the connection assets, the transmission assets and the generation assets.

The planning by Powercor is aimed at providing efficient and coordinated development of the sub-transmission and distribution systems. The objective is to determine the optimum level of investment in, and configuration of, distribution and subtransmission capacity, having regard for:

- the needs and preferences of their customers (the end consumers of electricity);
- the relative costs and benefits associated with alternative subtransmission and distribution development strategies, and alternative strategies aimed at delivering a level of supply reliability in accordance with consumers' needs; and

- the direct and indirect incentives (and penalties) faced by Powercor in relation to the reliability of the distribution network.

1.3 Powercor's obligations and liabilities as subtransmission and distribution planners

1.3.1 Statutory obligations under Victorian regulatory instruments

Section 3.5 of the Distribution Code requires each Distribution Business to:

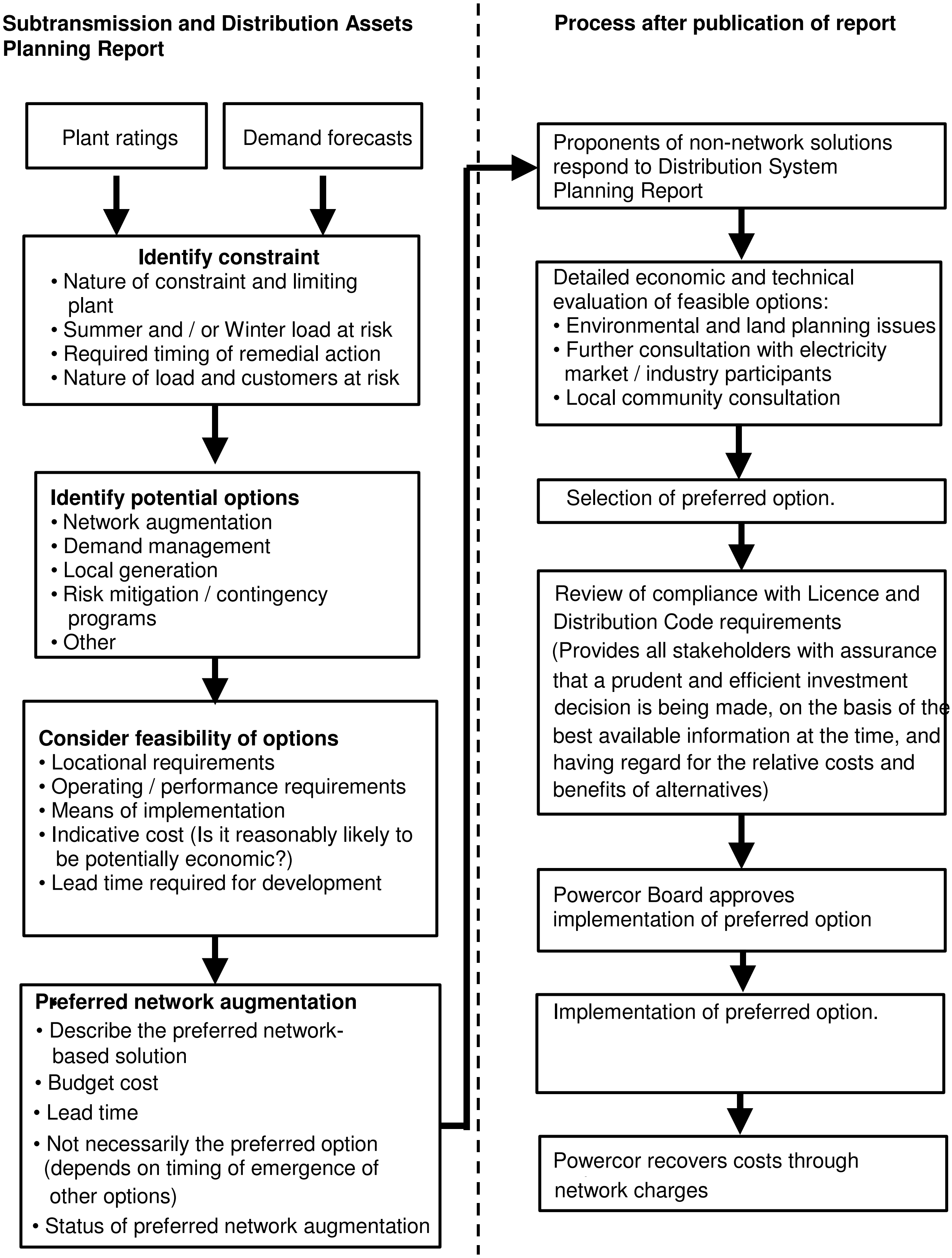
"Submit to the AER an annual report called the 'Distribution System Planning Report' detailing how it plans to meet predicted demand for electricity supplied through its subtransmission lines, zone substations and high voltage lines over the following five calendar years; and improve reliability to its customers".

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."

1.4 Overview of the Subtransmission and Distribution Planning Process

The flow chart below provides a summary of the distribution business planning and augmentation process.

PROCESS FLOW CHART: DISTRIBUTION SYSTEM PLANNING



2 PLANNING STANDARDS

2.1 Overall objective of subtransmission and distribution planning

The planning standards and criteria applied in the development of the network are a significant determinant of network-related costs. Costs associated with Powercor's facilities can be considered to comprise of:

- the direct cost of the service (as reflected in the use of system charges and the costs of losses); and
- indirect costs borne by customers as a consequence of supply interruptions caused by network outages.

In developing and applying the planning standards and investment criteria, Powercor aims to develop network assets or alternatives in an efficient manner that optimises the total direct life-cycle cost of network service borne by customers.

In addition, Powercor's investment decisions have regard for 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 system planning and investment evaluation

In some Australian jurisdictions, strict deterministic planning standards (for instance, "N-1") are applied across transmission and distribution system development. Powercor, however, takes in to account a risk-based deterministic approach when planning system development.

Under this combined planning approach, the strict deterministic 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 were out of service, however:

- in a network planned in accordance with the risk-based deterministic 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 risk maybe small when the likelihood of a forced outage of a particular element of the network is taken into consideration.

2.3 Application of the risk-based approach to planning

The risk-based planning approach involves the consideration of the likelihood of a plant outage coinciding with the peak loading season, and the consequence of that outage.

The quantity of energy at risk may be a critical parameter in justifying any network investment. Risk-based network planning aims to strike an economic balance between:

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

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 meet all anticipated loading requirements.

Implicit in this approach is acceptance of the risk that there may be circumstances when the planned zone substation 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 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 The augmentation criterion

All network investment decisions, for a project aimed at alleviating a network constraint, should be made having regard to:

- the relative costs and benefits, including any change in supply reliability, of network augmentation and non-network alternatives to augmentation;
- the uncertainty of assumptions that must necessarily be made in the decision analysis;
- the objective of minimising total life-cycle costs;
- the strong scale economies that exist within the electricity transmission and distribution sectors;
- the need to comply with environmental and land-use planning standards, health and safety standards and applicable technical standards, and
- augmentation of the network in a way which takes into account and minimises distribution losses.

2.5 Distribution Loss Consideration

Loss on the electrical network is an integral part within the planning of a network having a significant impact on supply voltage calculations. The selection of project solution inherently reduces system losses through change of conductor or plant support of voltage. Powercor as part of its plant selection process takes into account the cost of losses in its evaluation for transformer purchase.

3 RISK ASSESSMENT AND OPTIONS FOR ALLEVIATION OF CONSTRAINTS

3.1 Preamble

This Section presents an overview of the magnitude, probability and impact of loss of load at each zone substation and subtransmission line, in accordance with the requirements of clause 3.5.2(b) of the Distribution Code.

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

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

Similarly, high voltage line augmentation is generally in response to local developments, which may involve relatively short lead times and is addressed as part of the customer connection process. Where a major upgrade of the HV system is identified, such as the need for a new feeder, it would be considered in this report

In addition, capital expenditure is required from time to time to address other issues (eg. fault level, voltage code requirements). This expenditure is driven chiefly by mandatory health and safety standards, and does not relate only to capacity. These issues are 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 other issues.

The following key data are presented in this Section:

- ***Energy at risk:*** This is the amount of energy that would not be supplied from a zone substation if a major outage of a transformer occurs at that station in that particular year 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 augmentations or operational actions such as load transfers to other supply points to mitigate the impact of the outage. Similarly this concept can be applied to the outage of a subtransmission line.
- Estimates of energy at risk is based on the 50th percentile demand forecasts. 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.[1] The 50th percentile forecast can

[1] Conversely, there is a also 50% chance that actual demand will be *lower* than the forecast in any one year.

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.

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) or if a subtransmission line was out of service during a critical loading period.

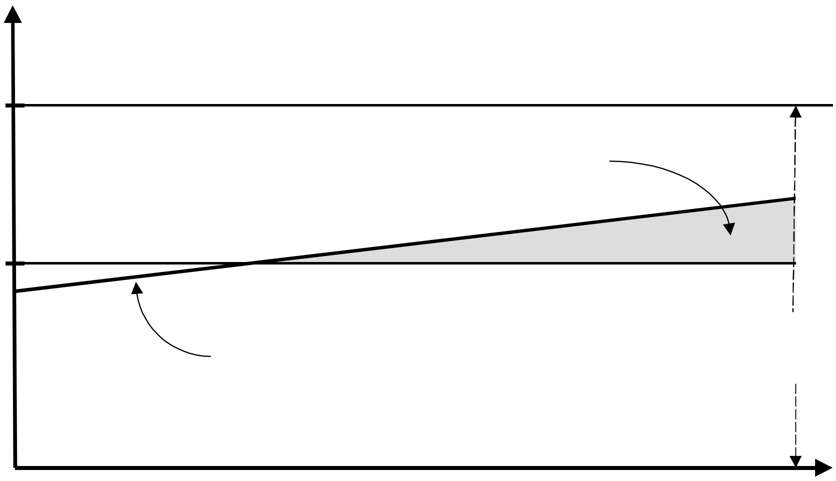


Figure 2: Energy at Risk

The capability of a zone substation with one transformer out of service is referred to as its "N minus 1" rating (N-1). 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 the diagram above.

- 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) 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 low but is very dependent upon the length of line exposure and the environment in which the line has to exist.

3.3 Asset Configuration

The Powercor zone substation and subtransmission line assets comprise of the following configurations. The configurations have been developed to provide the "economically and technically feasible optimum" asset to deliver supply to the customer.

3.3.1 Existing zone substation configurations :

1. Single transformer zone substation. This configuration comprises of a single transformer. For the contingent loss of this transformer customer supply is interrupted prior to restoration.

2. Banked transformer zone substation. This configuration comprises of multiple transformers but not segregated for system disturbances. For the contingent loss of a transformer customer supply is interrupted prior to restoration.

3. Switched transformer zone substation. This configuration comprises of multiple transformers segregated by circuit breakers for system disturbances. For the contingent loss of a transformer customer supply is not interrupted, as the remaining transformers provide continuity of supply.

3.3.2 Existing subtransmission line network configurations :

1. Single (radial) subtransmission line. This configuration comprises of a single power line. For the contingent loss of this line customer supply is interrupted prior to restoration.
2. Loop subtransmission network. This configuration comprises typically of two (or three) subtransmission lines segregated for system disturbances. For the contingent loss of a line customer supply is not interrupted, as the remaining lines provide continuity of supply.
3. Meshed subtransmission network. This configuration comprises of multiple subtransmission lines segregated for system disturbances. For the contingent loss of a line customer supply is not interrupted, as the remaining lines provide continuity of supply.

3.4 Risk assessments and options for alleviation of constraints on zone substations

The assessment presented in this section, summarised in tabulated form in Attachment 1, is not a detailed planning analysis but a high-level description of the expected balance between capacity and demand at each zone substation.

Attachment 2 provides the risk assessments and a description of the options available for alleviation of constraints, for the individual zone substation operating greater than 5 percent above their firm summer or winter rating for the coming year. The assessments provide a high-level description of the expected balance between capacity and demand at each zone substation for the next five year period. The zone substations addressed are set out in alphabetical order. For each station where augmentation is required, a preliminary estimate of the associated project costs are identified. This provides a broad indication of the potential value available to proponents of non-network solutions in deferring or avoiding network augmentation.

However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation. These issues should be considered by proponents of non-network solutions in assessing the implications of this report.

If it can be demonstrated that the proposed non-network solution provides a net economic benefit over a network solution, Powercor Australia will be prepared to negotiate a financial arrangement to share these benefits with the proposer of such a scheme, subject to verification of the financial arrangements by the Australian Energy Regulator where appropriate.

Notes associated with tables

The following notes are referred to in the tables and text provided in the zone substation attachments shown on the following pages.

Notes:

1. "N-1" means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. This is the percentage by which the forecast maximum demand exceeds the N-1 capability rating.
3. "Annual energy at risk" means the amount of energy that would not be supplied if a major outage of a transformer occurs at the station in that particular year and no other mitigation action is taken.
4. "Annual hours at risk" is the number of hours in a year during which the 50^{th} percentile demand forecast exceeds the N-1 capability rating.
5. There is an opportunity to develop a number of innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of demand reduction depends on the customer uptake and innovative network tariffs to encourage voluntary demand reduction. These initiatives could be taken into consideration when determining the optimum timing for the capacity augmentation.
6. By connecting embedded generation to the zone substation's 22kV bus, an emerging network constraint could be alleviated.
7. The probability of a major transformer outage occurring over the duration of the year is very low (0.217% per transformer).

3.5 Risk assessments and options for alleviation of constraints on subtransmission lines

The assessment presented in this section, summarised in tabulated form in Attachment 3, is not a detailed planning analysis but a high-level description of the expected balance between capacity and demand on each subtransmission line.

Attachment 4 details risk assessments and a description of the options available for alleviation of constraints, for each individual subtransmission line operating greater than 5 percent above their firm summer or winter rating for the coming year. The assessments, by line, are set out in alphabetical order. For each line, where augmentation is required, a preliminary estimate of the associated project costs are identified. This provides a broad indication of the potential value available to proponents of non-network solutions in deferring or avoiding network augmentation.

However, it should be noted that the value of a non-network solution depends on the extent to which it defers or avoids a network augmentation, and the expected timing of the network augmentation. These issues should be considered by proponents of non-network solutions in assessing the implications of this report.

If it can be demonstrated that the proposed non-network solution provides a net economic benefit over a network solution, Powercor Australia 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 Australian Energy Regulator.

Notes associated with tables

The following notes are referred to in the tables and text provided in the subtransmission line attachments shown on the following pages.

Notes:

1. This is the percentage by which the forecast maximum demand exceeds the line capability rating.
2. “Annual energy at risk” means the amount of energy that would not be supplied if a subtransmission line outage occurs in that particular year and no other mitigation action is taken.
3. “Annual hours at risk” is the number of hours in a year during which the 50th percentile demand forecast exceeds the N-1 capability rating.
4. There is an opportunity to develop a number of innovative customer schemes to encourage voluntary demand reduction during times of network constraint. The amount of demand reduction depends on the customer uptake and innovative network tariffs to encourage voluntary demand reduction. These initiatives could be taken into consideration when determining the optimum timing for the capacity augmentation.
5. By connecting embedded generation to existing network, an emerging constraint on the 66kV network could be alleviated.
6. The probability of a line outage occurring over the duration of the critical period during the year is very low. The average overhead 66kV line fault rate for Powercor is 10.9 faults per 100 km per annum.

4 DISTRIBUTION NETWORK RELIABILITY IMPROVEMENTS

Clause 3.5.3 of the Electricity Distribution Code, January 2011 requires 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.***

Powercor Australia LTD is committed to the delivery reliability service targets as set out in the AER determination of October 2010 "Victorian Electricity Distribution Network Service Providers - Distribution determination 2011–2015". In summary these targets are:

Reliability Measure	Urban Lines	Rural Short Lines	Rural Long Lines
Average unplanned minutes off supply per year (SAIDI)	82.47	114.81	233.76

A program established by Powercor Australia LTD to meet these reliability targets comprises several elements collectively known as Powercor's Reliability Improvement Strategy (RIS).

The RIS aims to maintain the substantial improvements in "Minutes off Supply" delivered over the previous regulatory period. The program includes, for example,

- Installation of remotely operable devices eg. Reclosers and Switches,
- Installation of remote fault indication devices,
- Reduction of the exposure to faults on the overhead distribution network,
- Enhanced asset management programs,
- Use of innovative solutions such as auxiliary power generation & by-pass cables and
- Improvements to fault management processes.

The following table indicates the forecast reliability performance of Powercor Australia LTD distribution network for 2011

Unplanned	AER Target	Forecast Performance Minutes Off Supply (SAIDI) @31/10/2011
	2011	**2011**
Urban lines	82.47	61.37
Rural Short Lines	114.81	100.36
Rural Long Lines	233.76	228.38

In 2011 the performance of Powercor's network was affected by a number of large events beyond the distributor's control. These have included severe flooding events in January and February and lightning storms September. The total impact of these events is an unplanned SAIDI of 72.63 minutes. These events have been excluded in the table above in accordance with the AER exclusion criteria for the calculation of financial incentives for supply reliability.

Powercor will continue to apply, enhance and fine tune the RIS program to deliver further long term sustainable reliability improvements areas to economically minimise the interruptions from planned and unplanned outages. It is important to keep in mind that the actual Network performance is also influenced by external events such as storms, drought and third party damage which may be outside Powercor's control. The influence of these factors on network performance can vary significantly from one year to the next.

Attachment 1 – Tabulated Summary of Zone Substations

Ratings and Demands for Zone Substations

Zone Sub		Nameplate Rating (MVA)	Cyclic N Rating (MVA)	Cyclic N-1 Rating (MVA)	Historical Demand (MVA)					50% POE Forecast Demand (MVA)					% Load Above N-1 Rating (2012)	Most likely contingency action to manage load at risk under (N-1) conditions
					2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
AC	S	54.0	58.0	30.0	10.9	9.2	6.9	13.5	9.8	10.6	2.4	2.4	2.4	2.5	-	-
	W	54.0	58.0	30.0	11.1	9.7	10.1	13.3	9.7	4.1	2.1	2.1	2.1	2.2	-	
AL	S	30.0	34.0	58.0	17.4	19.5	20.7	21.1	20.9	23.7	24.0	24.3	24.7	25.0	-	Full load backup by automatic transfer scheme to AC ZSS
	W	30.0	37.9	58.0	16.0	16.9	20.6	17.2	19.1	16.7	17.0	17.2	17.5	17.7	-	
ART	S	20.0	28.2	13.6	14.1	15.3	17.6	16.8	15.7	15.8	15.9	16.0	16.2	16.3	16.0	Transfers via 22kV network
	W	20.0	31.4	15.2	12.5	12.1	13.0	12.9	12.7	12.8	13.0	13.1	13.2	13.26	-	
BAN	S	120.0	145.4	96.4	86.6	89.7	104.0	90.6	87.1	91.5	92.8	94.2	95.1	93.8	-	-
	W	120.0	157.5	104.4	97.3	88.7	88.3	86.3	79.5	83.3	84.4	85.7	86.4	85.3	-	
BAS	S	99.0	116.8	76.0	59.2	64.1	71.9	71.3	72.0	74.4	75.8	78.6	81.5	86.4	-	-
	W	99.0	130.1	84.6	64.6	60.5	64.8	63.3	70.0	72.2	73.5	76.1	78.7	83.2	-	
BBD	S	33.0	47.2	0.0			11.8	16.9	18.0	19.9	21.5	22.4	23.1	23.6	100.0	Transfers via 22kV network for single transformer station
	W	33.0	50.0	0.0			8.0	7.0	12.6	13.6	14.6	15.4	15.8	16.3	100.0	
BGO	S	66.0	77.0	38.5	49.5	49.9	59.0	52.4	51.2	52.5	55.4	57.9	59.1	60.4	36.3	Transfers via 22kV network/ Emergency generation/ Load Management
	W	66.0	90.8	45.4	39.7	37.9	38.8	40.9	35.7	37.6	39.8	41.6	42.3	43.0	-	

Ratings and Demands for Zone Substations

Zone Sub		Nameplate Rating (MVA)	Cyclic N Rating (MVA)	Cyclic N-1 Rating (MVA)	Historical Demand (MVA) 2007	2008	2009	2010	2011	50% POE Forecast Demand (MVA) 2012	2013	2014	2015	2016	% Load Above N-1 Rating (2012)	Most likely contingency action to manage load at risk under (N-1) conditions
BMH	S	27.0	38.2	19.1	19.6	20.6	26.2	25.0	25.2	29.2	31.5	33.1	34.7	36.5	52.9	Transfers via 22kV network/Load Management
	W	27.0	40.4	20.2	17.8	20.1	21.3	21.2	22.4	23.8	25.7	27.0	28.3	29.7	17.8	
CDN	S	20.0	34.4	16.4	14.9	14.8	15.3	14.5	14.1	14.2	14.3	12.8	12.8	12.9	-	-
	W	20.0	36.4	16.4	17.6	17.1	16.5	16.7	16.2	16.3	16.4	14.5	14.5	14.6	-	
CHM	S	33.0	36.9	0.0	2.7	2.8	3.5	3.4	3.2	3.2	3.2	3.2	3.2	3.3	100.0	Transfers via 22kV network Emergency generation. Single transformer station.
	W	33.0	44.1	0.0	2.8	2.7	2.7	2.7	2.6	2.6	2.6	2.6	2.7	2.7	100.0	
CHA	S	27.0	30.4	15.2	17.5	17.0	17.5	16.2	13.1	17.4	17.6	17.8	18.1	18.3	14.4	Transfers via 22kV network/ Emergency generation/ Load Management
	W	27.0	30.4	15.2	16.1	16.2	13.7	12.5	12.9	12.7	12.8	13.0	13.2	13.3	-	
CLC	S	59.5	77.1	35.7	39.3	40.5	43.4	48.0	47.8	51.8	52.2	53.0	53.3	54.2	45.2	Transfers via 22kV network
	W	59.5	84.9	38.9	40.0	38.6	39.1	40.5	38.0	41.2	41.5	42.1	42.4	43.1	6.0	
CME	S	40.5	50.4	32.7	38.7	37.0	41.6	39.7	36.3	41.0	41.6	42.3	42.9	43.5	25.5	Transfers via 22kV network/ Emergency generation
	W	40.5	59.4	39.2	34.3	32.5	32.6	34.8	30.3	32.7	32.9	33.0	33.2	33.3	-	
CMN	S	51.8	65.9	22.9	20.5	22.8	26.7	22.9	21.7	22.4	22.2	22.7	23.2	23.7	-	-
	W	51.8	75.9	26.4	20.9	21.5	19.8	19.6	18.3	18.6	18.4	18.7	19.1	19.4	-	
COB	S	26.0	38.5	15.0	12.0	13.6	14.6	13.8	13.8	14.2	14.3	16.5	18.7	18.8	-	-
	W	26.0	39.0	15.0	11.2	14.2	12.7	13.7	13.7	14.0	14.0	16.2	18.4	18.5	-	
CRO	S	60.0	74.7	34.3	31.2	31.0	33.0	26.5	28.8	29.2	29.5	29.7	30.0	30.2	-	-
	W	60.0	82.4	38.0	28.4	27.3	25.2	20.2	24.6	25.0	25.2	25.4	25.6	25.7	-	

Ratings and Demands for Zone Substations

Zone Sub		Nameplate Rating (MVA)	Cyclic N Rating (MVA)	Cyclic N-1 Rating (MVA)	Historical Demand (MVA)					50% POE Forecast Demand (MVA)					% Load Above N-1 Rating (2012)	Most likely contingency action to manage load at risk under (N-1) conditions
					2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
CTN	S	27.0	33.2	16.6	20.7	20.8	23.5	23.3	20.1	22.1	22.3	22.6	22.9	23.2	32.8	Transfers via 22kV network/ Emergency generation/ Load Management
	W	27.0	40.2	20.1	19.6	18.6	18.8	17.0	18.6	18.8	19.0	19.2	19.3	19.5	-	
DDL	S	66.0	79.4	39.7	42.0	51.5	47.3	55.5	49.9	62.2	63.9	69.0	71.2	73.1	56.6	Transfers via 22kV network/ Emergency generation/ Load Management
	W	66.0	94.4	47.2	39.5	37.1	40.7	37.9	36.6	43.0	44.3	48.6	50.3	51.7	-	
DLF	S	66.0	80.0	40.0	3.6	3.5	7.7	21.3	24.5	24.8	27.1	27.5	27.8	28.1	-	-
	W	66.0	92.4	46.2	2.1	4.7	7.5	18.3	19.3	17.5	19.2	19.5	19.6	20.1	-	
ECA	S	39.5	52.8	34.6	35.3	35.1	38.2	36.6	34.9	36.8	37.1	37.4	37.8	38.1	6.3	Transfers via 22kV network
	W	39.5	60.6	40.4	33.5	30.5	29.3	33.5	28.3	30.1	30.2	30.2	30.3	30.4	-	
EHK	S	54.0	72.8	36.4	52.2	49.7	60.3	47.8	49.9	51.4	53.0	54.3	55.6	56.9	41.3	Transfers via 22kV network/ Emergency generation/ Load Management
	W	54.0	82.0	41.0	39.2	39.8	38.8	37.8	38.0	39.5	40.4	41.0	41.7	42.4	-	
FNS	S	99.0	130.8	87.2	39.8	41.9	43.2	42.0	38.0	39.6	41.7	43.0	43.6	47.4	-	-
	W	99.0	147.9	98.6	37.1	38.8	35.2	35.5	36.1	37.6	39.7	40.9	41.5	45.3	-	
GB	S	37.5	56.4	37.6	19.9	19.6	19.2	19.0	18.0	18.5	20.8	20.9	21.1	21.2	-	-
	W	37.5	56.4	37.6	18.8	18.7	18.5	17.1	17.0	17.5	19.9	20.0	20.2	20.3	-	
GCY	S	66.0	75.6	37.8	34.6	36.2	46.6	45.1	37.3	38.5	39.4	41.2	43.4	43.8	1.7	Transfers via 22kV network
	W	66.0	87.8	43.9	31.0	30.8	30.2	32.3	31.7	32.6	33.5	35.2	37.3	37.6	-	
GL	S	80.0	102.1	47.6	44.3	52.7	59.9	57.9	55.7	57.7	58.2	59.5	60.7	61.2	21.2	Transfers via 22kV network
	W	80.0	116.3	47.6	44.2	43.3	45.0	45.3	47.7	49.7	50.1	51.3	52.5	52.9	4.3	
GLE	S	40.5	52.2	34.8	39.6	45.9	50.2	50.1	47.9	44.9	48.1	52.1	54.4	56.0	28.9	Transfers via 22kV network/ Emergency generation/ Load Management
	W	40.5	57.9	38.6	39.6	38.8	40.4	38.9	43.2	40.1	43.2	46.9	49.1	50.5	4.0	

Ratings and Demands for Zone Substations

Zone Sub		Nameplate Rating (MVA)	Cyclic N Rating (MVA)	Cyclic N-1 Rating (MVA)	Historical Demand (MVA)					50% POE Forecast Demand (MVA)					% Load Above N-1 Rating (2012)	Most likely contingency action to manage load at risk under (N-1) conditions
					2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
HSM	S	40.5	59.6	39.7	43.0	45.2	49.1	46.5	44.5	46.5	46.9	47.3	47.7	48.1	17.2	Transfers via 22kV network/portable cooling fans/emergency generation
	W	40.5	60.6	40.4	35.7	34.2	36.0	34.0	33.6	35.3	35.6	35.9	36.2	36.5	-	
HTN	S	39.5	51.7	34.2	22.6	25.1	34.2	33.0	27.9	28.1	28.4	28.7	28.9	29.2	-	-
	W	39.5	58.1	38.4	25.6	26.6	27.9	28.2	28.1	28.3	28.6	28.9	29.1	29.4	-	
KRT	S	40.5	52.5	33.4	28.5	27.4	26.5	26.4	29.4	28.9	29.1	29.2	29.4	29.5	-	-
	W	40.5	57.8	37.6	29.6	30.0	28.5	29.3	34.0	33.7	33.9	34.1	34.3	34.4	-	
KYM	S	40.5	52.6	33.8	30.8	28.6	31.0	29.2	29.1	30.0	30.1	30.2	30.4	30.5	-	-
	W	40.5	59.0	38.8	23.6	21.4	21.6	25.1	19.8	21.5	21.5	21.5	21.5	21.5	-	
LV	S	93.0	100.5	68.0	70.5	78.7	91.7	83.4	82.0	87.5	92.8	96.3	100.0	103.9	28.7	Transfers via 22kV network
	W	93.0	118.3	81.9	68.0	65.2	70.9	68.3	65.5	69.1	73.7	76.5	79.5	82.7	-	
LVN22	S	99.0	123.3	79.7	59.4	67.8	71.9	83.1	87.3	100.1	104.2	108.5	116.1	120.9	25.6	Transfers via 22kV network
	W	99.0	131.7	85.0	64.1	69.0	67.3	80.0	79.6	88.2	91.8	95.6	102.4	106.6	3.8	
LVN11	S	20.0	32.5	0.0	11.6	11.6	11.6	12.2	12.2	12.5	12.5	12.5	12.5	12.5	100.0	Transfers via 22kV network
	W	20.0	35.9	0.0	11.9	11.9	11.9	12.0	12.0	12.1	12.1	12.1	12.1	12.1	100.0	
MBN	S	26.0	37.6	18.8	22.9	22.5	25.9	26.0	26.3	27.6	28.2	28.8	29.4	30.0	47.0	Transfers via 22kV network
	W	26.0	40.4	20.2	20.4	19.3	18.1	17.8	16.5	18.1	18.3	18.6	18.8	19.1	-	
MDA	S	66.0	79.4	39.7	49.8	50.8	53.0	54.4	53.6	56.6	58.4	60.1	61.8	63.5	42.6	Transfers via 22kV network
	W	66.0	89.2	44.6	42.8	36.7	37.1	39.2	38.7	41.4	42.3	43.2	44.2	45.1	-	
MLN	S	66.0	77.6	39.9	40.3	44.4	51.5	53.4	46.4	60.6	63.8	67.2	70.8	74.6	51.9	Transfers via 22kV network
	W	66.0	92.2	43.8	33.3	36.2	38.0	35.7	36.9	39.6	41.5	43.8	46.2	48.8	-	

Ratings and Demands for Zone Substations

Zone Sub		Nameplate Rating (MVA)	Cyclic N Rating (MVA)	Cyclic N-1 Rating (MVA)	Historical Demand (MVA)					50% POE Forecast Demand (MVA)					% Load Above N-1 Rating (2012)	Most likely contingency action to manage load at risk under (N-1) conditions
					2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
MNA	S	66.0	76.6	38.3	40.6	37.1	39.5	40.0	43.6	45.3	45.7	46.2	46.7	47.1	18.2	Transfers via 22kV network
	W	66.0	88.8	44.4	27.9	27.4	27.8	32.2	28.6	28.7	28.9	29.1	29.4	29.6	-	
MRO	S	27.0	36.6	18.3	21.2	20.7	23.0	24.2	21.9	23.1	24.0	24.5	24.9	25.4	26.2	Transfers via 22kV network/ Emergency generation/ Load Management
	W	27.0	40.4	20.2	16.3	15.9	17.3	17.9	17.7	18.4	19.0	19.3	19.6	19.9	-	
NHL	S	20.0	26.0	13.0	9.9	10.3	12.0	11.8	11.4	11.5	11.7	11.8	11.9	12.1	-	-
	W	20.0	32.4	16.2	9.0	10.6	8.4	8.3	8.3	8.4	8.4	8.5	8.5	8.6	-	
NKA	S	39.5	45.7	30.5	29.9	29.8	31.0	30.3	28.8	29.7	29.8	30.0	30.2	30.4	-	-
	W	39.5	45.7	30.5	29.0	26.9	26.5	29.5	24.7	26.0	26.0	26.0	26.0	26.0	-	
OYN	S	27.0	30.4	15.2	8.8	7.4	9.5	8.3	8.5	8.7	8.8	8.9	9.0	9.1	-	-
	W	27.0	30.4	15.2	8.9	8.4	7.5	8.0	8.0	8.1	8.2	8.2	8.3	8.4	-	
PLD	S	32.0	44.2	22.1	20.6	21.4	22.3	18.3	18.9	19.0	19.1	19.2	19.3	19.4	-	-
	W	32.0	48.0	24.0	22.1	21.5	22.4	19.3	20.1	20.2	20.3	20.4	20.5	20.6	-	
RVL	S	19.5	32.8	21.7	26.5	27.2	22.0	21.0	21.0	22.6	23.7	24.6	25.3	26.0	4.2	Transfers via 22kV network
	W	19.5	35.9	24.0	15.5	13.5	9.9	9.9	12.3	12.9	13.2	13.5	13.9	14.2	-	
SA	S	93.0	114.2	76.2	91.6	90.3	90.3	94.2	84.3	98.1	86.1	88.9	91.7	94.7	28.8	Transfers via 22kV network
	W	93.0	123.8	76.2	70.6	74.9	63.8	64.5	65.4	77.4	66.6	68.7	70.8	73.1	1.6	
SHL	S	40.5	55.5	36.7	33.6	36.1	39.4	37.3	36.3	39.5	40.5	41.5	42.6	43.6	7.6	Transfers via 22kV network/ Emergency generation/ Load Management
	W	40.5	60.6	40.4	32.4	30.2	28.4	25.6	25.1	25.9	26.5	27.2	27.9	28.6	-	
SHN	S	66.0	80.0	40.0	33.8	38.3	42.4	38.8	39.5	40.0	40.4	40.8	41.2	41.7	-	
	W	66.0	88.2	44.1	30.8	26.5	28.0	29.5	27.9	28.9	29.0	29.1	29.2	29.3	-	

Ratings and Demands for Zone Substations

Zone Sub		Nameplate Rating (MVA)	Cyclic N Rating (MVA)	Cyclic N-1 Rating (MVA)	Historical Demand (MVA)					50% POE Forecast Demand (MVA)					% Load Above N-1 Rating (2012)	Most likely contingency action to manage load at risk under (N-1) conditions
					2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
SHP	S	33.0	36.6	0.0	25.8	27.0	26.6	26.0	21.7	25.0	25.1	25.3	25.5	25.7	100.0	Transfers via 22kV network for single transformer station
	W	33.0	41.9	0.0	16.8	15.2	15.8	16.1	14.2	15.6	15.6	15.6	15.7	15.7	100.0	
SSE	S	66.0	91.0	44.7	29.1	29.0	43.1	46.4	64.2	70.4	106.8	111.8	117.4	120.9	57.6	Transfers via 22kV network.
	W	66.0	101.0	50.0	25.6	26.1	36.0	42.9	52.8	61.6	93.8	86.9	91.7	94.4	23.2	
STL	S	27.0	37.0	18.5	18.8	20.4	22.2	24.2	23.9	24.2	24.5	24.8	25.1	25.5	30.6	Transfers via 22kV network
	W	27.0	37.6	18.8	17.6	18.7	18.7	20.4	20.3	20.5	20.8	21.0	21.2	21.5	9.2	
STN	S	59.0	76.8	35.7	45.0	45.0	52.0	47.9	46.3	49.1	49.8	50.4	51.0	51.7	37.7	Transfers via 22kV network/ Emergency generation
	W	59.0	88.3	38.3	33.7	30.2	32.4	34.2	29.5	33.5	33.7	34.0	34.2	34.5	-	
SU	S	118.0	87.1	87.1	73.3	90.0	83.4	84.0	81.5	86.3	85.2	100.1	105.7	115.0	-	
	W	118.0	87.1	87.1	64.8	75.2	64.8	65.5	65.6	73.5	73.8	87.2	92.2	100.1	-	
TRG	S	27.0	38.4	19.2	21.1	20.5	20.6	20.6	18.8	18.9	19.0	19.1	19.2	19.3	-	Transfers via 22kV network
	W	27.0	38.8	19.4	22.5	23.0	22.9	22.0	21.3	21.4	21.5	21.6	21.7	21.8	10.3	
WBE	S	99.0	121.1	82.8	72.5	77.5	89.4	89.4	85.4	106.3	109.5	112.9	116.5	120.3	28.4	Transfers via 22kV network
	W	99.0	138.0	92.2	50.4	53.8	59.4	56.0	60.5	66.9	68.8	71.0	73.3	75.7	-	
WBL	S	40.5	57.3	38.2	44.0	48.1	50.9	50.4	49.4	50.4	51.1	51.8	52.6	53.3	32.0	Transfers via 22kV network/ Emergency generation/ Load Management
	W	40.5	63.3	42.2	43.0	43.1	42.4	44.9	37.5	44.3	44.8	45.4	46.0	46.6	4.9	
WIN	S	11.0	16.0	5.5	6.2	6.4	6.9	7.0	5.2	5.3	5.3	5.4	5.4	5.5	-	Transfers via 22kV network
	W	11.0	16.4	5.9	6.5	6.5	6.4	6.2	6.8	6.8	6.9	7.0	7.1	7.1	16.0	
WMN	S	33.0	47.2	17.2	11.0	12.2	13.1	13.1	14.2	16.9	18.7	20.1	21.1	21.9	-	-
	W	33.0	50.0	20.2	8.6	7.4	7.7	5.9	12.0	13.8	15.1	16.1	16.8	17.4	-	

Ratings and Demands for Zone Substations

Zone Sub		Nameplate Rating (MVA)	Cyclic N Rating (MVA)	Cyclic N-1 Rating (MVA)	Historical Demand (MVA)					50% POE Forecast Demand (MVA)					% Load Above N-1 Rating (2012)	Most likely contingency action to manage load at risk under (N-1) conditions
					2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
WND	S	66.0	88.0	38.3	34.9	36.7	45.1	43.4	42.7	46.0	47.7	49.5	51.4	53.3	20.1	Emergency generation/ Load Management
	W	66.0	90.0	43.2	49.4	54.3	49.0	48.9	49.5	49.4	50.3	51.2	52.2	53.1	14.4	
WPD	S	79.5	115.2	60.8	64.6	64.9	67.7	69.7	64.7	66.8	71.3	78.4	81.7	84.6	9.9	Transfers via 22kV network/emergency transformer
	W	79.5	120.2	60.8	63.0	55.4	53.8	53.8	54.8	56.8	61.3	68.4	71.7	74.5	-	

Notes: 1. Summer 2012 shown in table is the summer period 2011/12

2. Summer and winter predicted maximum demand MVA loads include the effect of reactive compensation at the stations.

3. Customer owned zone substations not included.

4. 22kV supply from Terminal stations are not included in this report. Refer to Powercor's Transmission Connection Planning Report.

Attachment 2 – Detail Risk Assessments of Zone Substations

3.5.1.1 ARARAT ZONE SUBSTATION (ART) 22kV

Asset Description

Ararat Zone Substation (ART) 22 kV comprises of two 13.5 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and for the contingent loss of one of the transformer results in total loss of supply for the zone substation before restoration. ART supplies the urban and rural customers in the area of Ararat and the surrounding communities.

Magnitude and impact of loss of load

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

Station: ART (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	30	33	37	42	46
Annual hours at risk [See Note 4 Sec 3.4]	3	5	6	7	9

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by improving the existing transformer cooling systems at ART.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to improve the existing transformer cooling systems at ART. It is expected that this project will not occur within the above forecast period. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.2 BENDIGO ZONE SUBSTATION (BGO) 22kV

Asset Description

Bendigo Zone Substation (BGO) 22 kV comprises of two 33 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a fully switched configuration and for the loss one of the transformers the other will maintain supply to the customers. BGO supplies the domestic, commercial and industrial areas of Bendigo.

Magnitude and impact of loss of load

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

Station: BGO (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	895	1446	2030	2354	2708
Annual hours at risk [See Note 4 Sec 3.4]	195	254	307	330	353

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by installing two 22kV feeders at Bendigo Terminal Station (BETS) and transfer load.

Preferred network option(s) for alleviation of constraints

It is proposed that the risk will be alleviated by installing two 22kV feeders at Bendigo Terminal Station (BETS) and transferring load. This project is planned for 2014. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.3 BACCHUS MARSH ZONE SUBSTATION (BMH) 22kV

Asset Description

Bacchus Marsh Zone Substation (BMH) 22 kV comprises of two 10/13.5 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and for the contingent loss of one of the transformer results in total loss of supply for the zone substation before restoration. BMH supplies the domestic, commercial, industrial and farming areas of Bacchus Marsh and surrounding areas along the Western Freeway.

Magnitude and impact of loss of load

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

Station: BMH (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	275	631	1032	1622	2542
Annual hours at risk [See Note 4 Sec 3.4]	122	217	315	490	803

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Augment existing inter-station ties for load transfer away to alternative supply points in contingency conditions.
- Augment BMH Zone substation by addition of a third 66/22kV, 25/33MVA transformer.
- Establish new 22kV feeder from Melton Zone substation (MLN).
- Increase contingency transfers to MLN after its augmentation by an additional third transformer.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be the installation of an additional 22kV feeder at MLN followed by an additional transformer at MLN. It is expected that the MLN feeder project will not occur before 2013 and the transformer project at MLN not before 2015 In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.4 BOUNDARY BEND ZONE SUBSTATION (BBD) 22kV

Asset Description

Boundary Bend Zone Substation (BBD) 22 kV comprises of one 25 MVA 66/22kV transformer supplying the 22 kV buses. The zone substation is a single transformer configuration and the contingent loss of the transformer results in total loss of supply for the zone substation. BBD supplies the township of Boundary Bend and a large surrounding irrigation area.

Magnitude and impact of loss of load

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

Station: BBD (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	51227	55174	57710	59516	60843
Annual hours at risk [See Note 4 Sec 3.4]	8760	8760	8760	8760	8760

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Construct new feeder ties to RVL (Robinvale) to increase load transfers away.
- Augment capacity by installing an additional 66/22kV transformer at BBD.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be the installation of an additional transformer at BBD. It is expected that this project will not occur before 2017. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.5 COHUNA ZONE SUBSTATION (CHA) 22kV

Asset Description

Cohuna Zone Substation (CHA) 22 kV comprises of two 10/13.5 MVA 66/22kV transformers. The zone substation is a banked configuration and for the contingent loss of one of the transformers results in total loss of supply for the zone substation before restoration. CHA supplies the domestic and commercial area of Cohuna extending into surrounding rural areas (some 4,380 customers). Cooling fans have been installed, but due to the existing 22kV transformer disconnect switches, a higher station rating cannot be realised.

Magnitude and impact of loss of load

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

Station: CHA (22kV)	**2012**	**2013**	**2014**	**2015**	**2016**
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	15.2	19.5	24.7	31.1	38.6
Annual hours at risk [See Note 4 Sec 3.4]	20	24	28	34	40

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by replacing the 22kV transformer disconnect switches at CHA.

Preferred network option(s) for alleviation of constraints

It is proposed that the next augmentation will be the replacement of existing 22kV transformer disconnect switches at CHA. It is expected that this project will not occur before 2015. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.6 COLAC ZONE SUBSTATION (CLC) 22kV

Asset Description

Colac Zone Substation (CLC) 22 kV comprises of one 33 MVA and two 13.5 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and for the contingent loss of one of the transformers results in total loss of supply for the zone substation before restoration. CLC supplies the domestic, commercial and rural dairy area of Colac.

Magnitude and impact of loss of load

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

Station: CLC (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	1368	1501	1873	2052	2608
Annual hours at risk [See Note 4 Sec 3.4]	518	563	694	758	952

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by replacing an existing 10/13.5MVA transformer with a 25/33 MVA 66/22 kV transformer at CLC.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be the replacement of an existing 10/13.5MVA transformer with a 25/33MVA transformer at CLC. It is expected that this project will not occur before 2013. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.7 COBRAM EAST ZONE SUBSTATION (CME) 22 kV

Asset Description

Cobram East Zone Substation (CME) 22 kV comprises of three 10/13.5 MVA 66/22 kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and the contingent loss of one of the transformers results in total loss of supply for the zone substation before restoration. CME supplies the towns of Cobram and Yarrawonga.

Magnitude and impact of loss of load

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

Station: CME (22 kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	632	745	873	1019	1184
Annual hours at risk [See Note 4 Sec 3.4]	188	209	233	258	289

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Augment capacity for transfers away to adjacent Numurkah (NKA) zone substation.
- Augment capacity by improving the existing transformer cooling systems at CME.
- Establish Cobram West (CMW) zone substation to off-load CME.
- Augment capacity by installing a new capacitor bank at CME.
- Bring supply to Yarrawonga from Essential Energy network in Mulwala (New South Wales).

Preferred network option(s) for alleviation of constraints

It is proposed that the next augmentation will be to improve the existing transformer cooling systems at CME. It is expected that this project will not occur before 2013. A feasibility study in 2013 will consider bringing supply from Essential Energy's network in Mulwala to supply Yarrawonga. It is expected that this project would not look to establish a new supply before 2015. In the interim, temporary generation and load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.8 CHARLTON ZONE SUBSTATION (CTN) 22kV

Asset Description

Charlton Zone Substation (CTN) 22 kV comprises of two 13.5 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and for the contingent loss of one of the transformer results in total loss of supply for the zone substation before restoration. CTN supplies the an area of approximately 80 square kilometres of rural Victoria, mainly open farm country, and numerous towns.

Magnitude and impact of loss of load

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

Station: CTN (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	406	465	531	604	682
Annual hours at risk [See Note 4 Sec 3.4]	290	314	333	356	375

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by improving the existing transformer cooling systems at CTN.
- Augment capacity by installing an additional 66/22 kV transformer at CTN.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be the installation of an additional transformer at CTN. This project is planned for 2012. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.9 DRYSDALE ZONE SUBSTATION (DDL) 22kV

Asset Description

Drysdale Zone Substation (DDL) 22 kV comprises two 33 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation has a fully switched configuration, so that for a transformer fault, one transformer will be isolated, and the other will continue to supply the station load. DDL supplies the domestic and commercial area of Drysdale and supplies the Bellarine Penysula and coastal towns.

Magnitude and impact of loss of load

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

Station: DDL (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	397	469	723	855	986
Annual hours at risk [See Note 4 Sec 3.4]	54	61	81	95	112

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by installing an additional 66/22kV transformer at DDL.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be the installation of an additional 25/33MVA transformer at DDL. It is expected that this project will not occur before 2016. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk. In addition, a new plant protection scheme, planned for 2011, will remove the potential for plant damage under unplanned contingency conditions at peak load.

3.5.1.10 ECHUCA ZONE SUBSTATION (ECA) 22 kV

Asset Description

Echuca Zone Substation (ECA) 22 kV comprises of one 10/13.5 MVA 66/22 kV transformer and two 10/13 MVA 66/22 kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and the contingent loss of one of the transformers results in total loss of supply for the zone substation before restoration. ECA supplies the towns of Echuca and Rochester.

Magnitude and impact of loss of load

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

Station: ECA (22 kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	72	86	102	119	140
Annual hours at risk [See Note 4 Sec 3.4]	2	2	2	2	2

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by improving the existing transformer cooling systems at ECA.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to improve the existing transformer cooling systems at ECA. It is expected that this project will not occur within the above forecast period. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.11 EAGLEHAWK ZONE SUBSTATION (EHK) 22kV

Asset Description

Eaglehawk Zone Substation (EHK) 22 kV comprises of two 27 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and for the contingent loss of one of the transformers results in total loss of supply for the zone substation before restoration. EHK supplies the domestic and commercial area of Eaglehawk extending into surrounding rural areas.

Magnitude and impact of loss of load

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

Station: EHK (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	658	853	1032	1239	1474
Annual hours at risk [See Note 4 Sec 3.4]	140	165	188	213	243

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by installing an additional 66/22kV transformer at EHK.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be the installation of an additional transformer at EHK. It is expected that this project will not occur before 2015. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.12 GEELONG ZONE SUBSTATION (GL) 22kV

Asset Description

Geelong Zone Substation (GL) 22 kV comprises two 20/40 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a fully switched configuration so that for a transformer fault, one transformer will be isolated, and the other will continue to supply the station load. GL supplies the domestic and commercial area of Geelong extending into surrounding north and western rural areas.

Magnitude and impact of loss of load

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

Station: GL (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	76	86	122	172	196
Annual hours at risk [See Note 4 Sec 3.4]	23	25	37	54	61

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by improving the existing transformer cooling systems at GL.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to improve the existing transformer cooling systems at GL. It is expected that this project will not occur within the above forecast period. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.13 GEELONG EAST ZONE SUBSTATION (GLE) 22kV

Asset Description

Geelong East Zone Substation (GLE) 22 kV comprises three 12.5 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and for the contingent loss of one of the transformer results in total loss of supply for the zone substation before restoration. GLE supplies the domestic and commercial area of Geelong East extending into surrounding rural areas.

Magnitude and impact of loss of load

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

Station: GLE (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	140	370	1526	3182	4773
Annual hours at risk [See Note 4 Sec 3.4]	41	96	424	837	1161

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by replacing two existing 10/13.5MVA transformers with 25/33 MVA 66/22 kV transformers at GLE.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be the replacement of two existing 10/13.5MVA transformers with 25/33MVA transformers at GLE. It is expected that this project will not occur before 2014/15. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.14 HORSHAM ZONE SUBSTATION (HSM) 22kV

Asset Description

Horsham Zone Substation (HSM) 22 kV comprises three 13.5 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and for the contingent loss of one of the transformers results in total loss of supply for the zone substation before restoration. HSM supplies the domestic and commecial area of Horsham extending into surrounding rural areas.

Magnitude and impact of loss of load

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

Station: HSM (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	85	95	107	120	134
Annual hours at risk [See Note 4 Sec 3.4]	28	29	32	35	38

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Transfer HSM load to a new CHM 22kV distribution feeder.
- Establish Warracknabeal (WNL) zone substation to off-load HSM.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to install a new CHM 22kV distribution feeder and permanently transfer the load to CHM zone substation. It is expected that this project will not occur within the above forecast period. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.15 LAVERTON ZONE SUBSTATION (LV) 22kV

Asset Description

Laverton Substation (LV) 22 kV comprises one 27 MVA and two 33 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation has a fully switched configuration, so that for a transformer fault, one transformer will be isolated, and the other will continue to supply the station load. LV supplies the domestic and commercial area of Laverton extending into surrounding urban areas of Altona Meadows, Tarneit, Hoppers Crossing and Point Cook.

Magnitude and impact of loss of load

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

Station: LV (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	528	985	1388	1916	2594
Annual hours at risk [See Note 4 Sec 3.4]	84	128	165	207	259

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Replace the existing 20/27MVA 66/22kV transformer No.1 at Laverton (LV) zone substation with a new 25/33MVA unit. This will provide additional capacity to reduce the Laverton zone substation load at risk to an acceptable level.
- New feeder from Brooklyn BLTS22 terminal station to off-load LV zone substation.
- Establish new Truganina (TNA) Zone substation and transfer load from LV. Note that the establishment of TNA will require new 66kV subtransmission lines from a new terminal station at Deer Park (DPTS). Refer to the Transmission Connection Planning Report for the background to the establishment of DPTS by 2016 to address loading issues at Keilor Terminal Station.

Preferred network option(s) for alleviation of constraints

Due to limited 22kV transfer away capacity (adjacent zone substations heavily loaded) it is proposed to replace the existing 20/27MVA 66/22kV transformer No.1 at Laverton (LV) with a new 25/33MVA transformer. The replacement will increase station N-1 rating by 12MVA, N cyclic rating by 20MVA and will not be required before 2014. After that Truganina (TNA) zone substation is the next planned augmentation and is not expected to occur before 2016. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.16 LAVERTON NORTH ZONE SUBSTATION (LVN) 22kV

Asset Description

Laverton North Zone Substation (LVN) 22 kV comprises of three 33 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a fully switched configuration and for the loss one of the transformers the other will maintain supply to the customers. LVN Zone substation supplies mostly the commercial and industrial sectors of Laverton North, Altona Meadows, Derrimut and surrounding area.

Magnitude and impact of loss of load

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

Station: LVN (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	399	2669	8273	19414	28496
Annual hours at risk [See Note 4 Sec 3.4]	212	667	1047	1573	2097

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by installing two new capacitor banks at LVN.
- Permanent load transfers to BLTS22.
- Establish new BLTS 22kV feeder and transfer load from LVN.
- Establish new Truganina (TNA) Zone Substation and transfer load from LVN. Note that the establishment of TNA will require new 66kV subtransmission lines from a new terminal station at Deer Park (DPTS). Refer to the Transmission Connection Planning Report for the background to the establishment of DPTS by 2016 to address loading issues at Keilor Terminal Station.

Preferred network option(s) for alleviation of constraints

It is planned to install two new capacitor banks at LVN in 2012. After that it is planned to carry out permanent load transfers to BLTS22 by 2013. Followed by new Truganina (TNA) zone substation which is not expected to occur before 2016. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.17 LAVERTON NORTH ZONE SUBSTATION (LVN) 11kV

Asset Description

Laverton North Zone Substation (LVN) 11 kV comprises of one 20/30 MVA 66/11kV transformer supplying the 11 kV bus and a single customer via dedicated sole use feeder. The zone substation has a fully switched configuration and for the loss of the single transformer the customer's automatic changeover system will transfer critical load to a backup 22/11kV transformer connected to the 22kV LVN network.

Magnitude and impact of loss of load

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

Station: LVN (11kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	75270	75270	75270	75270	75270
Annual hours at risk [See Note 4 Sec 3.4]	8760	8760	8760	8760	8760

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Augment capacity by installing a new 66/11kV transformer at LVN.

Preferred network option(s) for alleviation of constraints

As the single customer is supplied from the 11kV network and has an alternative supply arrangement for the critical load , there is no further requirement for augmentation at LVN (11kV).

3.5.1.18 MERBEIN ZONE SUBSTATION (MBN) 22kV

Asset Description

Merbein Zone Substation (MBN) 22 kV comprises of two 13 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and the contingent loss of one transformer results in total loss of supply for the zone substation before restoration. MBN supplies the township of Merbein and the surrounding rural area.

Magnitude and impact of loss of load

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

Station: MBN (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	989	1153	1335	1536	1758
Annual hours at risk [See Note 4 Sec 3.4]	337	374	409	447	488

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by installing a new 22kV feeder tie to Mildura (MDA) and transfer load.
- Augment capacity by installing an additional 66/22kV transformer.

Preferred network option(s) for alleviation of constraints

It is proposed that the risk will be alleviated by installing a 22kV feeder tie to Mildura (MDA). It is expected that this project will not occur before 2014. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.19 MILDURA ZONE SUBSTATION (MDA) 22kV

Asset Description

Mildura Zone Substation (MDA) 22 kV comprises of two 33 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a partially switched configuration. For a transformer fault the faulted transformer and approximately half station load will be isolated and the other transformer will continue to supply the remainder of the station load. MDA supplies the City of Mildura, the town of Irymple and a small irrigation area.

Magnitude and impact of loss of load

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

Station: MDA (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	1397	1827	2271	2784	3380
Annual hours at risk [See Note 4 Sec 3.4]	249	299	345	395	451

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by installing a new 22kV feeder tie to Merbein (MBN) and transfer load.
- Augment capacity by installing a third 66/22kV transformer.

Preferred network option(s) for alleviation of constraints

It is proposed that the risk will be alleviated by installing a 22kV feeder tie to Merbein (MBN). It is expected that this project will not occur before 2014. In addition, it is proposed to convert MDA to a fully switched station by reconfiguring the protection and installing a plant protection scheme to remove potential plant damange. It is expected that this project will not occur before 2013. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.20 MELTON ZONE SUBSTATION (MLN) 22kV

Asset Description

Melton Zone Substation (MLN) 22 kV comprises two 33 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation has a fully switched configuration, so that for a transformer fault, one transformer will be isolated, and the other will continue to supply the station load. MLN supplies the domestic, commercial and industrial area of Melton extending into surrounding rural areas.

Magnitude and impact of loss of load

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

Station: MLN (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	1080	1575	2227	3119	4449
Annual hours at risk [See Note 4 Sec 3.4]	191	246	319	446	676

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by installing a new capacitor bank at MLN.
- Augment capacity by installing an additional 66/22kV transformer at MLN.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be the installation of an additional transformer at MLN. It is expected that this project will not occur before 2015. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.21 MOOROOPNA ZONE SUBSTATION (MNA) 22 kV

Asset Description

Mooroopna Zone Substation (MNA) 22 kV comprises of two 20/27/33 MVA 66/22 kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and the contingent loss of one of the transformers results in total loss of supply for the zone substation before restoration. Mooroopna supplies the towns of Shepparton, Mooroopna, Tatura, and Murchison.

Magnitude and impact of loss of load

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

Station: MNA (22 kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	100	115	133	152	174
Annual hours at risk [See Note 4 Sec 3.4]	3	4	5	6	8

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by improving the existing transformer cooling systems at MNA.
- Augment capacity by installing an additional 66/22 kV transformer at MNA.
- Establish Tatura (TAT) zone substation to off-load MNA.
- Augment capacity by installing a new capacitor bank at MNA.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to either install a new capacitor bank or improve the existing transformer cooling systems at MNA. It is expected that this project will not occur within the above forecast period. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.22 MARYBOROUGH ZONE SUBSTATION (MRO) 22kV

Asset Description

Maryborough Zone Substation (MRO) 22 kV comprises of two 13 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and for the contingent loss of one of the transformers results in total loss of supply for the zone substation. MRO supplies the township of Maryborough and extending into surrounding rural areas.

Magnitude and impact of loss of load

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

Station: MRO (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	242	362	432	511	599
Annual hours at risk [See Note 4 Sec 3.4]	156	197	218	242	262

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by installing an additional 66/22 kV transformer at MRO.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be the installation of an additional transformer at MRO. It is expected that this project will not occur before 2016. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.23 ST ALBANS ZONE SUBSTATION (SA) 22kV

Asset Description

St Albans Zone Substation (SA) 22 kV comprises two 30 MVA and one 33 MVA 66/22kV transformers. The zone substation has a partially switched configuration and for the loss of one of the transformers the other two will maintain supply to the customers. SA supplies the domestic/commercial/ industrial areas of St Albans and is adjacent to SU (Sunshine) and SSE (Sunshine East) zone substations. All three substations share the load growth in the area.

Magnitude and impact of loss of load

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

Station: SA (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	353	51	91	149	230
Annual hours at risk [See Note 4 Sec 3.4]	50	13	19	27	37

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Permanently transfer load away to alternative supply points.
- Replace the transformer isolators to improve station cyclic rating
- Augment capacity by installing a third 66/22kV transformer and 22kV feeder at Sunshine East (SSE) and transfer load.

Preferred network option(s) for alleviation of constraints

The next augmentation is to increase feeder ties between SA and MLN (supplied from Keilor Terminal Station transformer group B3 & B4) and SSE zone substation (KTS transformer group B1, B2 & B5) to offload SA feeders and balance loads between transformer groups at KTS. Powercor has committed a project to install an additional transformer at SSE in late 2012 which will offload SA feeders and balance loads at KTS West group (B3 & B4). In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.24 SWAN HILL ZONE SUBSTATION (SHL) 22kV

Asset Description

Swan Hill Zone Substation (SHL) 22 kV comprises of three 10/13.5 MVA 66/22kV transformers. The zone substation is a banked configuration and for the contingent loss of one of the transformers results in total loss of supply for the zone substation before restoration. SHL supplies the approximately 9,320 customers in the domestic and commercial area of Swan Hill and extends into surrounding rural areas.

Magnitude and impact of loss of load

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

Station: SHL (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	15	31	56	95	148
Annual hours at risk [See Note 4 Sec 3.4]	13	21	33	47	64

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away/load management to alternative supply points.
- Augment capacity by installing an additional 66/22 kV transformer at SHL.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be the installation of an additional transformer at SHL. It is expected that this project will not occur before 2019. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.25 STANHOPE ZONE SUBSTATION (SHP) 22 kV

Asset Description

Stanhope Zone Substation (SHP) 22 kV comprises of one 25/33MVA 66/22kV transformer supplying the 22 kV buses. The contingent loss of the single transformer results in total loss of supply for the zone substation before restoration. SHP supplies the towns of Stanhope and Rushworth.

Magnitude and impact of loss of load

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

Station: SHP (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	82760	83216	83675	84137	84603
Annual hours at risk [See Note 4 Sec 3.4]	8760	8764	8760	8760	8760

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by installing an additional 66/22 kV transformer at SHP.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be the installation of an additional transformer at SHP. It is expected that this project will not occur before 2012. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.26 SUNSHINE EAST ZONE SUBSTATION (SSE) 22kV

Asset Description

Sunshine East Zone Substation (SSE) 22 kV comprises two 33 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation has a fully switched configuration, so that for a transformer fault, one transformer will be isolated, and the other will continue to supply the station load. SSE supplies the domestic, commercial and industrial area of Sunshine and Sunshine North and is adjacent to SU (Sunshine) and SA (St Albans) zone substations. SSE substation shares the load growth in the Sunshine area with SU so that the latter does not exceed it's 'N' cyclic rating.

Magnitude and impact of loss of load

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

Station: SSE (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	6432	81612	79277	94372	103959
Annual hours at risk [See Note 4 Sec 3.4]	1736	4857	4843	5276	5567

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by installing a new capacitor bank at SSE.
- Augment capacity by installing an additional 66/22 kV transformer at SSE.

Preferred network option(s) for alleviation of constraints

Powercor has committed a project to install an additional transformer at SSE. It is expected that this project will be constructed in late 2012. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.27 STAWELL ZONE SUBSTATION (STL) 22kV

Asset Description

Stawell Zone Substation (STL) 22 kV comprises two 13MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and for the contingent loss of one of the transformer results in total loss of supply for the zone substation before restoration. STL supplies the domestic, commercial and industrial area of Stawell.

Magnitude and impact of loss of load

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

Station: STL (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	356	454	579	741	943
Annual hours at risk [See Note 4 Sec 3.4]	350	454	583	738	924

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by installing a new 22kV feeder tie to Ararat (ART) and transfer load.

Preferred network option(s) for alleviation of constraints

It is proposed that the risk will be alleviated by installing a 22kV feeder tie to Ararat (ART). It is expected that this project will not occur before 2012. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.28 SHEPPARTON ZONE SUBSTATION (STN) 22 kV

Asset Description

Shepparton Zone Substation (STN) 22 kV comprises of one 25/33 MVA 66/22 kV transformer and two 13 MVA 66/22 kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and for the contingent loss of one of the transformer results in total loss of supply for the zone substation before restoration. STN supplies the domestic, commercial and industrial area of Shepparton.

Magnitude and impact of loss of load

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

Station: STN (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	1607	1774	1953	2146	2354
Annual hours at risk [See Note 4 Sec 3.4]	338	364	391	419	448

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by installing an additional 66/22 kV transformer at STN.

Preferred network option(s) for alleviation of constraints

Powercor has committed a project to install an additional transformer at STN. It is expected that this project will be completed in 2012. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.29 SUNSHINE ZONE SUBSTATION (SU) 22kV

Asset Description

Sunshine Zone Substation (SU) 22 kV comprises of a 38 MVA and a 45 MVA 66/22kV transformer in service supplying the 22 kV buses. A second pair of 17.5 MVA transformers are not switched in to limit fault levels at the station and remain on standby. The zone substation has a fully switched configuration, so that for a transformer fault, one transformer will be isolated, and the standby pair of transformers will be switched in to share the station load with the other transformer. SU supplies the domestic, commercial and industrial area of Sunshine, and Sunshine West and North and is adjacent to LVN (Laverton North), SSE (Sunshine East) and SA (St Albans) zone substations.

Magnitude and impact of loss of load

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

Station: SU (22kV)	2012	2013	2014	2015	2016
Annual unserved energy (MWh) [See Note 3 Sec 3.4]	0	0	84	261	1679
Annual unserved hours [See Note 4 Sec 3.4]	0	0	20	64	395

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to alleviate the emerging constraint (load above system normal rating i.e. unserved) (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Replacement of all aged transformers at Sunshine.
- Augment capacity by establishing new Truganina (TNA) zone substation to off-load SU ZSS as well as LV, LVN & WBE. Note that the establishment of TNA will require new 66kV subtransmission lines from a new terminal station at Deer Park (DPTS). Refer to the Transmission Connection Planning Report for the background to the establishment of DPTS by 2016 to address loading issues at Keilor Terminal Station. DPTS will also supply MLN & SU requiring 66kV loop lines to these stations.

Preferred network option(s) for alleviation of constraints

Replacement of existing 66/22kV SU zone substation transformers with new 25/33MVA units is planned as part of a asset renewal project. This project is planned in stages beginning in 2012 with the first new transformer able to increase system normal capacity not expected to occur before 2014. After that a new Truganina (TNA) zone substation is not expected to occur before 2016. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.30 TERANG ZONE SUBSTATION (TRG) 22kV

Asset Description

Terang Zone Substation (TRG) 22 kV comprises of two 13.5 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and for the contingent loss of one of the transformer results in total loss of supply for the zone substation before restoration. TRG supplies the township of Terang, extending into surrounding rural dairy areas.

Magnitude and impact of loss of load

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

Station: TRG (22kV)	**2012**	**2013**	**2014**	**2015**	**2016**
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	22	26	31	36	42
Annual hours at risk [See Note 4 Sec 3.4]	45	50	57	64	71

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by improving the existing transformer cooling systems at TRG.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to improve the existing transformer cooling systems at TRG. It is expected that this project will not occur within the above forecast period. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.31 WARRNAMBOOL ZONE SUBSTATION (WBL) 22kV

Asset Description

Warrnambool Zone Substation (WBL) 22 kV comprises of three 13.5 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a banked configuration and for the contingent loss of one of the transformer results in total loss of supply for the zone substation before restoration. WBL supplies the township of Warrnambool and extending into surrounding rural areas.

Magnitude and impact of loss of load

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

Station: WBL (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	277	334	405	492	601
Annual hours at risk [See Note 4 Sec 3.4]	85	104	124	151	187

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint. (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Establish new zone substation Allansford (AFD) to off-load WBL.

Preferred network option(s) for alleviation of constraints

The establishment of an alternative supply point at a new Allansford (AFD) zone substation is not expected to occur within the above forecast period. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.32 WERRIBEE ZONE SUBSTATION (WBE) 22kV

Asset Description

Werribee Substation (WBE) 22 kV comprises three 33 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation has a fully switched configuration, so that for a transformer fault, one transformer will be isolated, and the other will continue to supply the station load. WBE supplies the domestic and commercial area of Werribee, Hoppers Crossing, Wyndham Vale and Point Cook extending into surrounding rural areas (Mount Cottrell).

Magnitude and impact of loss of load

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

Station: WBE (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	471	650	877	1157	1506
Annual hours at risk [See Note 4 Sec 3.4]	62	77	92	110	134

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Replace the existing 20/27MVA 66/22kV transformer No.1 at Laverton (LV) zone substation with a new 25/33MVA unit. It will provide a spare capacity to offload the Werribee zone substation.
- New feeder from Brooklyn BLTS22 terminal station to off-load LV zone substation and WBE zone substation.
- Augment capacity by establishing new Truganina (TNA) zone substation to off-load LV & WBE ZSS. Note that the establishment of TNA will require new 66kV subtransmission lines from a new terminal station at Deer Park (DPTS). Refer to the Transmission Connection Planning Report for the background to the establishment of DPTS by 2016 to address loading issues at Keilor Terminal Station.

Preferred network option(s) for alleviation of constraints

Replacement of existing 66/22kV LV zone substation transformer No.1 by a new 25/33MVA unit and offloading WBE to LV is not expected to occur before 2014. After that a new Truganina (TNA) zone substation is not expected to occur before 2016. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.33 WINCHELSEA ZONE SUBSTATION (WIN) 22kV

Asset Description

Winchelsea Zone Substation (WIN) 22 kV comprises of one 5 MVA and one 4 MVA 66/22kV transformer supplying the 22 kV buses. The zone substation is a banked configuration and for the contingent loss of one of the transformer results in total loss of supply for the zone substation before restoration. WIN supplies the township of Winchelsea and extending into surrounding rural areas.

Magnitude and impact of loss of load

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

Station: WIN (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	29	38	49	61	75
Annual hours at risk [See Note 4 Sec 3.4]	122	147	180	205	241

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Augment capacity by replacing an existing 66/22kV transformer at WIN.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to replace the existing 4MVA transformer with a larger unit. It is expected that this project will not occur before 2014. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.34 WOODEND ZONE SUBSTATION (WND) 22kV

Asset Description

Woodend Zone Substation (WND) 22 kV comprises two 33 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation has a fully switched configuration and for the loss of one of the transformers the other will maintain supply to the customers. WND supplies the domestic, commercial and rural area of Woodend and Gisborne.

Magnitude and impact of loss of load

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

Station: WND (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	272	467	757	1180	1783
Annual hours at risk [See Note 4 Sec 3.4]	154	234	339	480	667

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Establish new zone substation Gisborne (GSB) to off-load WND.
- Augment capacity by installing an additional transformer at WND.

Preferred network option(s) for alleviation of constraints

Powercor has committed a project to establish a new zone substation, Gisborne (GSB). It is expected that this project will be completed in 2012. This will also mitigate risk on the SBY-WND #2 66kV line. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.35 WAURN PONDS ZONE SUBSTATION (WPD) 22kV

Asset Description

Waurn Ponds Zone Substation (WPD) 22 kV comprises of one 13.5 MVA and two 33 MVA 66/22kV transformers supplying the 22 kV buses. The zone substation is a fully switched configuration so that for a transformer fault, one transformer will be isolated, and the other will continue to supply the station load. WPD supplies the domestic and commercial area of Waurn Ponds extending into the surfcoast areas.

Magnitude and impact of loss of load

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

Station: WPD (22kV)	2012	2013	2014	2015	2016
Annual energy at risk (MWh) [See Note 3 Sec 3.4]	25	82	324	653	1125
Annual hours at risk [See Note 4 Sec 3.4]	9	18	76	151	245

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 5 & 6, Section 3.4 for a description of options common to all zone substations):

- Contingency plan to transfer load away to alternative supply points.
- Establish new zone substation Torquay (TQY) to off-load WPD.
- Augment capacity by replacing the existing 10/13.5MVA transformer with a 25/33MVA 66/22kV transformer at WPD.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to establish a new Torquay (TQY) zone substation. This will also mitigate risk on 22kV distribution feeders. It is expected that this project will not occur before 2017. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk. In addition, a new plant protection scheme, planned for 2013, will remove the potential for plant damage under unplanned contingency conditions at peak load.

Attachment 3 – Tabulated Summary of Subtransmission Lines

Subtransmission Line		Capacity (Amps)	Predicted MD for Summer 2011/12 and Winter 2012		Annual Energy at Risk (MWh)	Annual Hours at Risk	Most likely contingency action to manage load at risk under (N-1) conditions
			Amps	% > N-1 Capacity			
AC-CPL	**S**	810	Not above n-1 rating		-	-	-
	W	815	Not above n-1 rating				
ART-STL	**S**	285	Not above n-1 rating		-	-	-
	W	380	Not above n-1 rating				
ATS-AC	**S**	810	Not above n-1 rating		-	-	-
	W	815	Not above n-1 rating				
ATS-BLTS	**S**	855	Not above n-1 rating		-	-	-
	W	925	Not above n-1 rating				
ATS-HCP	**S**	895	Not above n-1 rating		-	-	-
	W	1075	Not above n-1 rating				
ATS-LV #1	**S**	895	Not above n-1 rating		-	-	-
	W	1075	Not above n-1 rating				
ATS-LV #2	**S**	895	Not above n-1 rating		-	-	-
	W	1075	Not above n-1 rating				
ATS-WBE	**S**	TBA	Not above n-1 rating		-	-	-
	W	TBA	Not above n-1 rating				
ATS-LVN	**S**	960	1065	10.9%	260	122	Transfer via 22kV Network/Load Management
	W	1075	Not above n-1 rating				
ATS-SCI (Radial Line)	**S**	795	Not above n rating		-	-	-
	W	800	Not above n rating				
ATS-TYA	**S**	895	Not above n-1 rating		-	-	-
	W	1075	Not above n-1 rating				
BAN-BGR	**S**	170	Not above n-1 rating		-	-	-
	W	365	Not above n-1 rating				

Subtransmission Line		Capacity (Amps)	Predicted MD for Summer 2011/12 and Winter 2012		Annual Energy at Risk (MWh)	Annual Hours at Risk	Most likely contingency action to manage load at risk under (N-1) conditions
			Amps	% > N-1 Capacity			
BATS-BAN #1	**S**	730	Not above n-1 rating		-	-	-
	W	900	Not above n-1 rating				
BATS-BAN #2	**S**	730	Not above n-1 rating		-	-	-
	W	900	Not above n-1 rating				
BATS-BAS #1	**S**	730	Not above n-1 rating		-	-	-
	W	900	Not above n-1 rating				
BATS-BAS #2	**S**	560	755	34.8%	452	76	Transfers via 22kV network / Apply Limited Cyclic Ratings
	W	700	Not above n-1 rating				
TEE-OFF BATS-BAS #2 TO BGF	**S**	915	Not above n-1 rating		-	-	-
	W	1110	Not above n-1 rating				
BATS-BMH (Radial Line)	**S**	230	346	50.4%	388	107	Transfers via 22kV network / Apply Limited Cyclic Ratings
	W	320	Not above n-1 rating				
TEE-OFF BATS-BMH TO BGL	**S**	230	Not above n-1 rating		-	-	-
	W	320	Not above n-1 rating				
BCG-WPD	**S**	1025	Not above n-1 rating		-	-	-
	W	1105	Not above n-1 rating				
BETS-BGO	**S**	920	Not above n-1 rating		-	-	-
	W	930	Not above n-1 rating				
BETS-CMN	**S**	520	Not above n-1 rating		-	-	-
	W	520	Not above n-1 rating				
BETS-CTN (Radial Line)	**S**	240	262	9.2%	23	35	Transfers via 22kV network/ Emergency generation/ Load Management
	W	240	Not above n rating				
BETS-EHK	**S**	895	919	2.7%	22	4	Transfers via 22kV network
	W	905	Not above n-1 rating				
BETS-MRO	**S**	600	Not above n-1 rating		-	-	-
	W	600	Not above n-1 rating				
BGO-EHK	**S**	425	470	10.6%	69	24	Transfers via 22kV network
	W	430	Not above n-1 rating				

Subtransmission Line		Capacity (Amps)	Predicted MD for Summer 2011/12 and Winter 2012		Annual Energy at Risk (MWh)	Annual Hours at Risk	Most likely contingency action to manage load at risk under (N-1) conditions
			Amps	% > N-1 Capacity			
BGR-ART	S	360	Not above n-1 rating		-	-	-
	W	420	Not above n-1 rating				
BLTS-AL	S	800	Not above n-1 rating		-	-	-
	W	800	Not above n-1 rating				
BLTS-BMH (Radial Line)	S	255	310	21.6%	103	42	Transfers via 22kV network/ Apply limited cyclic rating
	W	285	Not above n rating				
BLTS-LVN	S	855	1097	28.3%	4865	881	Transfers via 22kV network / Load Management
	W	925	937	1.3%			
BLTS-SCI (Radial Line)	S	988	Not above n rating		-	-	-
	W	988	Not above n rating				
BLTS-TYA	S	720	Not above n-1 rating		-	-	-
	W	720	Not above n-1 rating				
CLC-CDN	S	360	559	55.3%	881	216	Transfers via 22kV network / Apply Limited Cyclic Ratings
	W	500	Not above n-1 rating				
CMN-MRO	S	255	258	1.2%	1	1	-
	W	285	Not above n-1 rating				
COB-CDN	S	430	Not above n-1 rating		-	-	-
	W	500	Not above n-1 rating				
CPL-AL	S	800	Not above n-1 rating		-	-	-
	W	800	Not above n-1 rating				
FBTS – DLF #1	S	765	Not above n-1 rating		-	-	-
	W	800	Not above n-1 rating				
FBTS – DLF #2	S	765	Not above n-1 rating		-	-	-
	W	800	Not above n-1 rating				
FDN-CRO	S	960	Not above n-1 rating		-	-	-
	W	1105	Not above n-1 rating				
FNS-SRC	S	915	Not above n-1 rating		-	-	-
	W	980	Not above n-1 rating				

Subtransmission Line		Capacity (Amps)	Predicted MD for Summer 2011/12 and Winter 2012		Annual Energy at Risk (MWh)	Annual Hours at Risk	Most likely contingency action to manage load at risk under (N-1) conditions
			Amps	% > N-1 Capacity			
GB-GL	S	690	881	27.7%	224	30	Transfers via 22kV network / Apply Limited Cyclic Ratings
	W	835	Not above n-1 rating				
GLE-DDL #1	S	340	607	78.5%	624	74	Transfers via 22kV network / Apply Limited Cyclic Ratings
	W	390	410	5.1%			
GLE-DDL #2	S	345	626	81.4%	751	94	Transfers via 22kV network / Apply Limited Cyclic Ratings
	W	390	416	6.7%			
GL-GCY	S	650	Not above n-1 rating		-	-	-
	W	1105	Not above n-1 rating				
GTS-BCG	S	1025	Not above n-1 rating		-	-	-
	W	1105	Not above n-1 rating				
GTS-CRO	S	720	Not above n-1 rating		-	-	-
	W	720	Not above n-1 rating				
GTS-FDN	S	720	Not above n-1 rating		-	-	-
	W	720	Not above n-1 rating				
GTS-FNS	S	890	Not above n-1 rating		-	-	-
	W	955	Not above n-1 rating				
GTS-GB	S	690	959	39.0%	732	113	Transfers via 22kV network / Apply Limited Cyclic Ratings
	W	740	797	7.7%			
GTS-GCY	S	890	961	8.0%	24	6	Transfers via 22kV network / Apply Limited Cyclic Ratings
	W	955	Not above n-1 rating				
GTS-GLE #1	S	690	1034	49.9%	843	71	Transfers via 22kV network / Apply Limited Cyclic Ratings
	W	740	Not above n-1 rating				
GTS-GLE #2	S	690	1115	61.6%	1434	113	Transfers via 22kV network / Apply Limited Cyclic Ratings
	W	740	779	5.3%			
GTS-SRC	S	915	Not above n-1 rating		-	-	-
	W	1105	Not above n-1 rating				
GTS-WIN	S	545	Not above n-1 rating		-	-	-
	W	660	Not above n-1 rating				

Subtransmission Line		Capacity (Amps)	Predicted MD for Summer 2011/12 and Winter 2012		Annual Energy at Risk (MWh)	Annual Hours at Risk	Most likely contingency action to manage load at risk under (N-1) conditions
			Amps	% > N-1 Capacity			
GTS-WPD	**S**	1025	Not above n-1 rating		-	-	-
	W	1105	Not above n-1 rating				
HCP-WBE	**S**	960	Not above n-1 rating		-	-	-
	W	1075	Not above n-1 rating				
HOTS-HSM #1	**S**	430	Not above n-1 rating		-	-	-
	W	470	Not above n-1 rating				
HOTS-HSM #2	**S**	430	Not above n-1 rating		-	-	-
	W	470	Not above n-1 rating				
HOTS-NHL (Radial Line)	**S**	335	Not above n rating		-	-	-
	W	380	Not above n rating				
HOTS-STL #1	**S**	430	Not above n-1 rating		-	-	-
	W	500	Not above n-1 rating				
HOTS-STL #2	**S**	170	207	21.8%	26	22	Transfers via 22kV network / Apply Limited Cyclic Ratings
	W	360	Not above n-1 rating				
HTH-OYN (Radial Line)	**S**	180	Not above n rating		-	-	-
	W	310	Not above n rating				
HTH-RVL (Radial Line)	**S**	180	Not above n rating		-	-	-
	W	310	Not above n rating				
KGTS-CHA (Radial Line)	**S**	325	Not above n rating		-	-	-
	W	350	Not above n rating				
KGTS-SHL #1	**S**	360	446	20.0%	161	59	Transfers via 22kV network/ Emergency generation/ Load Management
	W	360	Not above n-1 rating				
KGTS-SHL #2	**S**	360	398	7.1%	13	11	Transfers via 22kV network/ Emergency generation/ Load Management
	W	360	Not above n-1 rating				
KRT-PLD #1	**S**	260	Not above n-1 rating		-	-	-
	W	260	Not above n-1 rating				
Tee-off KRT-PLD #1 to CWF	**S**	570	Not above n-1 rating		-	-	-
	W	610	Not above n-1 rating				
KRT-PLD #2	**S**	260	Not above n-1 rating		-	-	-
	W	260	Not above n-1 rating				

Subtransmission Line		Capacity (Amps)	Predicted MD for Summer 2011/12 and Winter 2012		Annual Energy at Risk (MWh)	Annual Hours at Risk	Most likely contingency action to manage load at risk under (N-1) conditions
			Amps	% > N-1 Capacity			
Tee-off KRT-PLD #2 to YWF	S	830	Not above n-1 rating		-	-	-
	W	885	Not above n-1 rating				
KTS-MLN	S	825	874	5.9%	7.4	3.2	Transfers via 22kV network / Apply Limited Cyclic Ratings
	W	880	Not above n-1 rating				
KTS-SA #1	S	880	Not above n-1 rating		-	-	-
	W	925	Not above n-1 rating				
KTS-SA #2	S	915	Not above n-1 rating		-	-	-
	W	925	Not above n-1 rating				
KTS-SSE	S	735	Not above n-1 rating		-	-	-
	W	765	Not above n-1 rating				
KTS-SU #1	S	800	Not above n-1 rating		-	-	-
	W	800	Not above n-1 rating				
KTS-SU #2	S	855	Not above n-1 rating		-	-	-
	W	1100	Not above n-1 rating				
KYM-ECA #1	S	400	Not above n-1 rating		-	-	-
	W	470	Not above n-1 rating				
KYM-ECA #2	S	400	Not above n-1 rating		-	-	-
	W	470	Not above n-1 rating				
KYM-SHP	S	915	Not above n-1 rating		-	-	-
	W	980	Not above n-1 rating				
MBN-DTN (Radial Line)	S	650	Not above n rating		-	-	-
	W	760	Not above n rating				
MDA-MBN	S	650	Not above n-1 rating		-	-	-
	W	760	Not above n-1 rating				
MLN-SBY	S	960	Not above n-1 rating		-	-	-
	W	1075	Not above n-1 rating				
MNA-STN	S	435	460	5.7%	14	12	Transfers via 22kV network / Apply Limited Cyclic Ratings
	W	470	Not above n-1 rating				
NKA-CME (Radial Line)	S	650	Not above n rating		-	-	-
	W	760	Not above n rating				

Subtransmission Line		Capacity (Amps)	Predicted MD for Summer 2011/12 and Winter 2012		Annual Energy at Risk (MWh)	Annual Hours at Risk	Most likely contingency action to manage load at risk under (N-1) conditions
			Amps	% > N-1 Capacity			
OYN-IMK (Radial Line)	S	750	Not above n rating		-	-	-
	W	960	Not above n rating				
RCTS-HTH (Radial Line)	S	255	Not above n rating		-	-	-
	W	285	Not above n rating				
RCTS-MBN	S	850	Not above n-1 rating		-	-	-
	W	980	Not above n-1 rating				
RCTS-MDA #1	S	915	Not above n-1 rating		-	-	-
	W	980	Not above n-1 rating				
RCTS-MDA #2	S	915	Not above n-1 rating		-	-	-
	W	980	Not above n-1 rating				
RCTS-RVL (Radial Line)	S	370	Not above n rating		-	-	-
	W	400	Not above n rating				
RVL-BBD (Radial Line)	S	590	Not above n rating		-	-	-
	W	590	Not above n rating				
SBY-WND #1	S	360	456	26.7%	89	38	Transfers via 22kV network/Apply plant protection scheme
	W	510	Not above n-1 rating				
SBY-WND #2	S	360	476	32.2%	2321	714	Transfers via 22kV network/Apply plant protection scheme
	W	360	505	40.3%			
SHTS-KYM #1	S	700	Not above n-1 rating		-	-	-
	W	775	Not above n-1 rating				
SHTS-KYM #2	S	700	Not above n-1 rating		-	-	-
	W	775	Not above n-1 rating				
SHTS-MNA	S	890	Not above n-1 rating		-	-	-
	W	955	Not above n-1 rating				
SHTS-NKA #1	S	860	Not above n-1 rating		-	-	-
	W	860	Not above n-1 rating				
SHTS-NKA #2	S	800	Not above n-1 rating		-	-	-
	W	800	Not above n-1 rating				
SHTS-SHN #1	S	480	Not above n-1 rating		-	-	-
	W	480	Not above n-1 rating				

Subtransmission Line		Capacity (Amps)	Predicted MD for Summer 2011/12 and Winter 2012		Annual Energy at Risk (MWh)	Annual Hours at Risk	Most likely contingency action to manage load at risk under (N-1) conditions
			Amps	% > N-1 Capacity			
SHTS-SHN #2	S	480	Not above n-1 rating		-	-	-
	W	480	Not above n-1 rating				
SHTS-SHP	S	890	Not above n rating		-	-	-
	W	980	Not above n rating				
SHTS-STN	S	800	836	4.5%	59	18	Transfers via 22kV network
	W	800	Not above n-1 rating				
SU-SSE	S	705	Not above n-1 rating		-	-	-
	W	710	Not above n-1 rating				
TGTS-CDN	S	500	Not above n-1 rating		-	-	-
	W	720	Not above n-1 rating				
TGTS-COB	S	915	Not above n-1 rating		-	-	-
	W	980	Not above n-1 rating				
TGTS-NRB	S	435	Not above n-1 rating		-	-	-
	W	470	Not above n-1 rating				
NRB-OWF	S	915	Not above n-1 rating		-	-	-
	W	980	Not above n-1 rating				
NRB-HTN	S	440	Not above n-1 rating		-	-	-
	W	470	Not above n-1 rating				
TGTS-HTN #2	S	360	Not above n-1 rating		-	-	-
	W	420	Not above n-1 rating				
TGTS-KRT #1	S	340	Not above n-1 rating		-	-	-
	W	380	Not above n-1 rating				
TGTS-KRT #2	S	850	Not above n-1 rating		-	-	-
	W	980	Not above n-1 rating				
TGTS-TRG #1	S	700	Not above n-1 rating		-	-	-
	W	800	Not above n-1 rating				
TGTS-TRG #2	S	700	Not above n-1 rating		-	-	-
	W	800	Not above n-1 rating				
TRG-WBL #1	S	335	Not above n-1 rating		-	-	-
	W	450	Not above n-1 rating				

Subtransmission Line		Capacity (Amps)	Predicted MD for Summer 2011/12 and Winter 2012		Annual Energy at Risk (MWh)	Annual Hours at Risk	Most likely contingency action to manage load at risk under (N-1) conditions
			Amps	% > N-1 Capacity			
TRG-WBL #2	S	340	Not above n-1 rating		-	-	-
	W	400	Not above n-1 rating				
WBL-KRT	S	350	Not above n-1 rating		-	-	-
	W	405	Not above n-1 rating				
WIN-CLC	S	650	Not above n-1 rating		-	-	-
	W	760	Not above n-1 rating				

Attachment 4 – Detail Risk Assessments of Subtransmission Lines

3.5.1.36 ALTONA TERMINAL STATION– LAVERTON NORTH ZONE SUBSTATION SUBTRANSMISSION LINE CIRCUIT (ATS-LVN) 66kV

Asset Description

The Altona Terminal station to Laverton Zone Substation 66kV circuit line comprises of 2.47 km of 66kV overhead conductor. The line is switched by a 66kV circuit breaker off the No.1 66kV bus at Altona Terminal station. This line is in a 66kV loop configuration from ATS/BLTS Terminal station and for the loss of this line the other lines will maintain supply to the customers. LVN supplies mainly the commercial, and industrial areas of Laverton, Altona and surrounding areas.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Sub-transmission Line: ATS-LVN (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	122	128	132	142	147
Summer % Overload [See Note 1 Sec 3.5]	8.5	13.7	17.6	25.8	31.1
50th percentile Winter Maximum Demand (MVA)	103	108	112	120	125
Winter % Overload [See Note 1 Sec 3.5]	0	0	0	0	0
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	260	1350	3031	8758	13624
Annual hours at risk [See Note 3 Sec 3.5]	122	388	625	1068	1325

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all sub-transmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Reduce line load by installing two new capacitor banks at LVN to address zone substation loading constraint.
- Establish new BLTS 22kV feeder and transfer load from LVN to address zone substation loading constraint.

Preferred network option(s) for alleviation of constraints

It is also proposed to install 22kV capacitor banks at LVN Zone substation in 2012 which will reduce 66kV load on line and mitigate the load at risk. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.37 BALLARAT TERMINAL–BALLARAT SOUTH ZONE SUBSTATION SUBTRANSMISSION LINE No. 2 CIRCUIT (BATS-BAS#2) 66kV

Asset Description

The Ballarat Terminal to Ballarat South Zone Substation No.2 circuit 66kV line comprises of 11.94 km of 66kV overhead conductor, including the tee off to Ballarat Golf Fields (BGF). The line is switched by a 66kV circuit breaker off the No.2 66kV bus at Ballarat Terminal station. This line is in a loop network configuration with the BATS-BAS #1 66kV line, and for the loss of one line, the other will maintain supply to the customers. The loop supplies mainly the domestic, commercial and industrial areas South of Ballarat.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: BATS-BAS #2 (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	86.3	87.8	90.9	94.1	99.5
Summer % Overload [See Note 1 Sec 3.5]	34.9	37.2	42.1	47.0	55.4
50th percentile Winter Maximum Demand (MVA)	79.3	80.7	83.4	86.2	90.9
Winter % Overload [See Note 1 Sec 3.5]	-	0.8	4.3	7.7	13.6
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	452	545	789	1127	2074
Annual hours at risk [See Note 3 Sec 3.5]	76	90	126	179	361

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Transfer load away to adjacent supply points.
- Additional reactive compensation at BAS zone substation to reduce line loading.
- Augment capacity by uprating the SPAus Net exit conductor at BATS.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to uprate the BATS exit conductor of the BATS-BAS #2 line. It is expected that this project will not occur within the above forecast period. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.38 BALLARAT TERMINAL–BACCHUS MARSH ZONE SUBSTATION SUBTRANSMISSION LINE CIRCUIT (BATS-BMH) 66kV

Asset Description

The Ballarat Terminal Bacchus Marsh Zone Substation circuit 66kV line comprises of 52 km of 66kV overhead conductor. The line is switched by a 66kV circuit breaker off the No.1 66kV bus at Ballarat Terminal station. This line is in a radial line with a tee off to BGL customer switching station. BATS-BMH is currently running as the standby line for BMH in the event of the loss of the BLTS-BMH line that normally supplies BMH, and for the loss of the BLTS-BMH line, it will maintain supply to the customers. BATS-BMH supplies mainly the rural domestic, commercial and industrial load in and around the area of Bacchus Marsh.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: BATS-BMH (66kV)	**2012**	**2013**	**2014**	**2015**	**2016**
50th percentile Summer Maximum Demand (MVA)	39.6	42.9	44.9	47.0	49.2
Summer % Overload [See Note 1 Sec 3.5]	50.4	63.0	70.7	78.7	87.1
50th percentile Winter Maximum Demand (MVA)	31.7	34.1	35.6	37.2	38.9
Winter % Overload [See Note 1 Sec 3.5]	-	-	-	1.6	6.2
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	388	713	975	1324	1802
Annual hours at risk [See Note 3 Sec 3.5]	107	169	218	293	398

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by thermally uprating the BATS-BMH line.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to thermally uprate the BATS-BMH line. This augmentation is planned to be completed in 2012. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.39 BENDIGO TERMINAL – CHARLTON ZONE SUBSTATION SUBTRANSMISSION LINE (BETS- CTN) 66kV

Asset Description

The Bendigo Terminal Station to Charlton Zone Substation 66kV line comprises of 103.4 km of 66kV overhead conductor. This is radial 66kV line from the Bendigo Terminal station providing firm supply to Charlton zone substations.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: BETS- CTN (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	31.3	32.0	32.9	33.7	35.0
Summer % Overload [See Note 1 Sec 3.5]	9.2	12.0	15.1	18.0	22.2
50th percentile Winter Maximum Demand (MVA)	24.3	24.4	24.8	25.1	25.4
Winter % Overload [See Note 1 Sec 3.5]	-	-	-	-	-
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	23	52	104	174	316
Annual hours at risk [See Note 3 Sec 3.5]	35	54	84	107	149

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by reconductoring the BETS-CTN line in stages.
- Augment capacity by establishing a new 66kV line to Charlton.
- Emergency generation and load management.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to partly reconductor the BETS-CTN line. This will reduce the line loading due to the reduction in losses. This project is planned for 2012, with further sections to be reconductored in stages throughout the above forecast period. In the interim, the load on the line will be monitored, and load transfers away to alternative supply points and emergency generation will be utilised, if necessary to mitigate load at risk.

3.5.1.40 BENDIGO TERMINAL – EAGLEHAWK ZONE SUBSTATION SUBTRANSMISSION LINE (BETS-EHK) 66kV

Asset Description

The Bendigo Terminal Station to Eaglehawk Zone Substation Station 66kV line comprises of 7.0 km of 66kV overhead conductor. The line is part of a 66kV loop from the Bendigo Terminal station providing firm supply to both Bendigo and Eaglehawk zone substations. This line is in a 66kV loop configuration and for the loss of this line the other lines will maintain supply to the customers. BETS-EHK supplies the Bendigo and Eaglehawk areas.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: BETS-EHK (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	110.9	117.3	121.8	125.3	127.8
Summer % Overload [See Note 1 Sec 3.5]	3.7	9.6	13.9	17.3	19.4
50th percentile Winter Maximum Demand (MVA)	80.3	84.0	87.2	88.1	90.0
Winter % Overload [See Note 1 Sec 3.5]	-	-	-	-	-
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	22	96	193	304	400
Annual hours at risk [See Note 3 Sec 3.5]	4	11	17	24	28

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by installing a 22kV feeder at Bendigo Terminal Station (BETS) and transferring load.

Preferred network option(s) for alleviation of constraints

It is proposed that the risk will be alleviated by installing a 22kV feeder at Bendigo Terminal Station (BETS) and transfer load. This project is planned for 2014. The establishment of the BETS-BGO #2 line will further mitigate the risk, but is not expected within the above forecast period. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.41 BENDIGO ZONE SUBSTATION – EAGLEHAWK ZONE SUBSTATION SUBTRANSMISSION LINE (BGO-EHK) 66kV

Asset Description

The Bendigo Zone Substation Station to Eaglehawk Zone Substation 66kV line comprises of 5.2 km of 66kV overhead conductor. The line is part of a 66kV loop from the Bendigo Terminal station providing firm supply to both Bendigo and Eaglehawk zone substations. This line is in a 66kV loop configuration and for the loss of this line the other lines will maintain supply to the customers. BGO-EHK supplies the Bendigo and Eaglehawk areas.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: BGO-EHK (66kV)	2012	2013	2014	2015	2016
50^{th} percentile Summer Maximum Demand (MVA)	55.1	58.9	61.7	63.3	64.4
Summer % Overload [See Note 1 Sec 3.5]	9.2	16.9	22.4	25.6	27.8
50^{th} percentile Winter Maximum Demand (MVA)	38.6	41.2	43.3	43.7	44.7
Winter % Overload [See Note 1 Sec 3.5]	-	-	-	-	-
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	69	248	494	694	855
Annual hours at risk [See Note 3 Sec 3.5]	24	53	88	114	130

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by installing a 22kV feeder at Bendigo Terminal Station (BETS) and transferring load.

Preferred network option(s) for alleviation of constraints

It is proposed that the risk will be alleviated by installing a 22kV feeder at Bendigo Terminal Station (BETS) and transfer load. This project is planned for 2014. The reconductor of the BGO-EHK line is not expected before 2016. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.42 BROOKLYN TERMINAL – LAVERTON NORTH SUBSTATION SUBTRANSMISSION LINE CIRCUIT (BLTS-LVN) 66kV

Asset Description

The Brooklyn Terminal station to Laverton Zone Substation 66kV circuit line comprises of 6.78 km of 66kV overhead conductor. The line is switched by a 66kV circuit breaker off the No.1 66kV bus at Brooklyn Terminal station. This line is in a 66kV loop configuration from ATS/BLTS Terminal station and for the loss of this line the other lines will maintain supply to the customers. LVN supplies mainly the commercial, and industrial areas of Laverton, Altona and surrounding areas.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Sub-transmission Line: BLTS-LVN (66kV)	**2012**	**2013**	**2014**	**2015**	**2016**
50th percentile Summer Maximum Demand (MVA)	122	127	133	143	149
Summer % Overload [See Note 1 Sec 3.5]	21.5	26.6	32.3	42.3	48.7
50th percentile Winter Maximum Demand (MVA)	106	110	115	124	129
Winter % Overload [See Note 1 Sec 3.5]	0	1.8	6.3	14.2	19
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	4865	8595	13872	28087	40114
Annual hours at risk [See Note 3 Sec 3.5]	881	1157	1605	2700	3263

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all sub-transmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Reduce line load by installing two new capacitor banks at LVN to address zone substation and line loading constraint.
- Increase line capacity by replacing the 66kV circuit breaker at Brooklyn Terminal Station by higher rated unit.
- Permanent load transfers to BLTS22.
- Establish a new BLTS 22kV feeder and transfer load from LVN to address zone substation loading constraint.
- Establish new Truganina (TNA) Zone Substation and transfer load from LVN. Note that the establishment of TNA will require new 66kV subtransmission lines from a new terminal station at Deer Park (DPTS). Refer to the Transmission Connection Planning Report for the background to the establishment of DPTS by 2016 to address loading issues at Keilor Terminal Station.

Preferred network option(s) for alleviation of constraints

It is planned to install two new 22kV capacitor banks at LVN Zone substation in 2012 which will reduce 66kV load on line and mitigate the load at risk. It is also planned to increase line rating by replacement of the BLTS-LVN 66kV line exit circuit breaker at BLTS in 2013. After that it is planned to carry out permanent load transfers to BLTS22 by 2013. Followed by new Truganina (TNA) zone substation which is not expected to occur before 2016. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.43 BROOKLYN TERMINAL – BACCHUS MARSH SUBSTATION SUBTRANSMISSION LINE CIRCUIT (BLTS-BMH) 66kV

Asset Description

The Brooklyn Terminal station to Bacchus Marsh Substation 66kV circuit line comprises of 56.36 km of 66kV overhead conductor. The line is switched by a 66kV circuit breaker off the No.1 66kV bus at Brooklyn Terminal station. This line is in a 66kV open loop configuration from BATS Terminal station with auto changeover facility to maintain supply to the customers for the loss of BLTS-BMH line. BMH supplies the domestic, commercial, industrial and farming areas of Bacchus Marsh and surrounding sectors along Western Freeway.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Sub-transmission Line: BLTS-BMH (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	36.4	42	47.4	53	58.5
Summer % Overload [See Note 1 Sec 3.5]	21.7	40.6	58.6	77.2	95.7
50th percentile Winter Maximum Demand (MVA)	27.3	30.3	32.3	34.9	37.4
Winter % Overload [See Note 1 Sec 3.5]	0	0	0	4.4	11.8
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	102	436	1048	1474	1947
Annual hours at risk [See Note 3 Sec 3.5]	42	120	232	322	417

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all sub-transmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment 66kV overhead line by replacing small sized conductors by larger conductors in order to increase line thermal rating and improve system voltage.
- Establish new MLN 22kV feeder and third transformer at MLN and permanently transfer load from BMH to MLN.

Preferred network option(s) for alleviation of constraints

It is proposed to augment small sized conductor of BLTS-BMH line 66kV overhead lines with higher sized conductor in stages. It is expected that this project will not occur to commence before 2013. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.44 CAMPERDOWN ZONE SUBSTATION–COLAC SUBSTATION SUBTRANSMISSION LINE (CDN-CLC) 66kV

Asset Description

The Camperdown Zone Substation to Colac Zone Substation 66kV line comprises of 50 km of 66kV overhead conductor. The line is part of the 66kV tie between Terang and Geelong Terminal Stations, assistin in providing supply to Zone Substations in the area. For the loss of this line the other lines will the customers. CDN-CLC supplies the Camperdown and Colac area.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: CDN-CL (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	63.9	64.3	65.3	65.7	66.8
Summer % Overload [See Note 1 Sec 3.5]	55.1	56.1	58.5	59.5	62.1
50th percentile Winter Maximum Demand (MVA)	51.2	51.6	52.3	52.6	53.5
Winter % Overload [See Note 1 Sec 3.5]	-	-	-	-	-
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	881	949	1122	1212	1465
Annual hours at risk [See Note 3 Sec 3.5]	216	240	294	319	392

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by part uprating the CDN-CLC line.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to part uprate the CDN-CLC line. It is expected this project will not occur before 2014. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.45 GEELONG B ZONE SUBSTATION–GEELONG ZONE SUBSTATION SUBTRANSMISSION LINE (GB-GL) 66kV

Asset Description

The Geelong B Substation to Geelong Zone Substation 66kV line comprises of 2.8 km of 66kV overhead conductor. The line is part of a 66kV loop from the Geelong Terminal station providing firm supply to Geelong, Geelong B and Geelong City zone substations. This line is in a 66kV tie configuration and for the loss of this line the other lines will maintain supply to the customers. GB-GL supplies the Geelong area.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: GB-GL (66kV)	**2012**	**2013**	**2014**	**2015**	**2016**
50th percentile Summer Maximum Demand (MVA)	100.7	102.2	105.4	109.0	110.0
Summer % Overload [See Note 1 Sec 3.5]	27.6	29.6	33.6	38.2	39.4
50th percentile Winter Maximum Demand (MVA)	78.1	79.3	82.0	85.2	85.9
Winter % Overload [See Note 1 Sec 3.5]	-	-	-	-	-
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	224	264	365	513	560
Annual hours at risk [See Note 3 Sec 3.5]	30	33	44	60	65

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by reconductoring the GB-GL line.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to reconductor the GB-GL line. It is expected that this project will not occur within the above forecast period. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.46 GEELONG EAST ZONE SUBSTATION–DRYSDALE ZONE SUBSTATION SUBTRANSMISSION LINE No.1 CIRCUIT (GLE-DDL#1) 66kV

Asset Description

The Geelong East Zone Substation to Drysdale Zone Substation number 1 66kV line comprises of 20.30 km of 66kV overhead conductor. The line is part of a 66kV loop from the Geelong Terminal station providing firm supply to Drysdale zone substation. This line is in a 66kV tie configuration and for the loss of this line the other lines will maintain supply to the customers. GLE – DDL #1 supplies the Drysdale area.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: GLE-DDL #1 (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	69.4	71.3	77.0	79.5	81.5
Summer % Overload [See Note 1 Sec 3.5]	76.1	80.9	95.6	101.8	106.9
50th percentile Winter Maximum Demand (MVA)	46.9	48.3	52.9	54.8	56.3
Winter % Overload [See Note 1 Sec 3.5]	2.6	5.6	15.8	19.9	23.2
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	624	724	1154	1449	1769
Annual hours at risk [See Note 3 Sec 3.5]	74	86	162	230	299

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by part reconductoring the GLE-DDL #1 line.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to part reconductoring the GLE-DDL #1 line. This augmentation is planned to be completed in 2013. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk. In addition, a new plant protection scheme, planned for 2011, will remove the potential for plant damage under unplanned contingency conditions at peak load.

3.5.1.47 GEELONG EAST ZONE SUBSTATION–DRYSDALE ZONE SUBSTATION SUBTRANSMISSION LINE No.2 CIRCUIT (GLE-DDL#2) 66kV

Asset Description

The Geelong East Zone Substation to Drysdale Zone Substation number 2 66kV line comprises of 20.22 km of 66kV overhead conductor. The line is part of a 66kV loop from the Geelong Terminal station providing firm supply to Drysdale zone substation. This line is in a 66kV tie configuration and for the loss of this line the other lines will maintain supply to the customers. GLE – DDL #2 supplies the Drysdale area.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: GLE-DDL #2 (66kV)	2012	2013	2014	2015	2016
50^{th} percentile Summer Maximum Demand (MVA)	71.6	73.5	79.5	82.0	84.1
Summer % Overload [See Note 1 Sec 3.5]	81.6	86.6	101.7	108.1	113.4
50^{th} percentile Winter Maximum Demand (MVA)	47.6	49.0	53.7	55.6	57.1
Winter % Overload [See Note 1 Sec 3.5]	9.6	12.9	23.7	28.1	31.6
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	751	883	1583	2074	2595
Annual hours at risk [See Note 3 Sec 3.5]	94	118	277	383	488

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by part reconductoring the GLE-DDL #2 line.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to part reconductoring the GLE-DDL #2 line. This augmentation is planned to be completed in 2012. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk. In addition, a new plant protection scheme, planned for 2011, will remove the potential for plant damage under unplanned contingency conditions at peak load.

3.5.1.48 GEELONG TERMINAL–GEELONG B ZONE SUBSTATION SUBTRANSMISSION LINE (GTS-GB) 66kV

Asset Description

The Geelong Terminal Station to Geelong B Zone Substation 66kV line comprises of 6.61 km of 66kV overhead conductor. The line is part of a 66kV loop from the Geelong Terminal station providing firm supply to Geelong, Geelong B and Geelong City zone substations. This line is in a 66 kV tie configuration and for the loss of this line the other lines will maintain supply to the customers. GTS-GB supplies the Geelong area.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: GTS-GB (66kV)	2012	2013	2014	2015	2016
50^{th} percentile Summer Maximum Demand (MVA)	109.6	113.2	116.3	119.7	120.7
Summer % Overload [See Note 1 Sec 3.5]	38.9	43.5	47.4	51.7	53.0
50^{th} percentile Winter Maximum Demand (MVA)	91.1	94.5	97.2	100.4	101.2
Winter % Overload [See Note 1 Sec 3.5]	7.7	11.7	14.9	18.6	19.6
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	732	1120	1609	2422	2709
Annual hours at risk [See Note 3 Sec 3.5]	113	175	254	389	431

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by reconductoring the GTS-GB line.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to reconductor the GTS-GB line. This augmentation is planned to be completed in 2013. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk. In addition, a new plant protection scheme, planned for 2012, will remove the potential for plant damage under unplanned contingency conditions at peak load.

3.5.1.49 GEELONG TERMINAL–GEELONG CITY ZONE SUBSTATION SUBTRANSMISSION LINE (GTS-GCY) 66kV

Asset Description

The Geelong Terminal Station to Geelong City Zone Substation 66kV line comprises of 10.8 km of 66kV overhead conductor. The line is part of a 66kV loop from the Geelong Terminal station providing firm supply to Geelong, Geelong B, and Geelong City zone substations. This line is in a 66kV tie configuration and for the loss of this line the other lines will maintain supply to the customers. GTS-GCY supplies the Geelong and Geelong City areas.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: GTS-GCY (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	109.9	113.5	116.5	120.0	121.0
Summer % Overload [See Note 1 Sec 3.5]	8.0	11.6	14.6	18.0	19.0
50th percentile Winter Maximum Demand (MVA)	91.0	94.4	97.1	100.2	101.0
Winter % Overload [See Note 1 Sec 3.5]	-	-	-	-	-
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	24	46	72	111	125
Annual hours at risk [See Note 3 Sec 3.5]	6	8	11	15	17

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by part reconductoring the GTS-GCY line.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to part reconductor the GTS-GCY line. It is expected that this project will not occur within the above forecast period. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk. In addition, a new plant protection scheme, planned for 2012, will remove the potential for plant damage under unplanned contingency conditions at peak load.

3.5.1.50 GEELONG TERMINAL–GEELONG EAST ZONE SUBSTATION SUBTRANSMISSION LINE No.1 CIRCUIT (GTS-GLE#1) 66kV

Asset Description

The Geelong Terminal Station to Geelong East Zone Substation number 1 66kV line comprises of 15.51 km of 66kV overhead conductor. The line is part of a 66kV loop from the Geelong Terminal station providing firm supply to both Geelong East and Drysdale zone substations. This line is in a 66kV tie configuration and for the loss of this line the other lines will maintain supply to the customers. GTS-GLE #1 supplies the Geelong East and Drysdale areas.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: GTS-GLE #1 (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	118.2	123.6	133.8	138.8	142.5
Summer % Overload [See Note 1 Sec 3.5]	49.8	56.7	69.5	75.9	80.6
50th percentile Winter Maximum Demand (MVA)	84.4	88.7	96.9	100.8	103.7
Winter % Overload [See Note 1 Sec 3.5]	-	4.9	14.5	19.2	22.5
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	843	1163	2104	2890	3682
Annual hours at risk [See Note 3 Sec 3.5]	71	94	194	291	388

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by reconductoring the GTS-GLE #1 line.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to reconductor the GTS-GLE #1 line. This augmentation is planned to be completed in 2013. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk. In addition, a new plant protection scheme, planned for 2011, will remove the potential for plant damage under unplanned contingency conditions at peak load.

3.5.1.51 GEELONG TERMINAL–GEELONG EAST ZONE SUBSTATION SUBTRANSMISSION LINE No.2 CIRCUIT (GTS-GLE#2) 66kV

Asset Description

The Geelong Terminal Station to Geelong East Zone Substation number 2 66kV line comprises of 23.04 km of 66kV overhead conductor. The line is part of a 66kV loop from the Geelong Terminal station providing firm supply to both Geelong East and Drysdale zone substations. This line is in a 66kV tie configuration and for the loss of this line the other lines will maintain supply to the customers. GTS-GLE #2 supplies the Geelong East and Drysdale areas.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: GTS-GLE #2 (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	127.5	133.3	144.2	149.7	153.7
Summer % Overload [See Note 1 Sec 3.5]	61.5	69.0	82.8	89.7	94.8
50th percentile Winter Maximum Demand (MVA)	89.1	93.7	102.3	106.4	109.4
Winter % Overload [See Note 1 Sec 3.5]	5.3	10.7	20.9	25.8	29.3
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	1434	1972	3783	5361	6966
Annual hours at risk [See Note 3 Sec 3.5]	113	162	384	590	795

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by part reconductoring the GTS-GLE #2 line.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to part reconductor the GTS-GLE #2 line. This augmentation is planned to be completed in 2012. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk. In addition, a new plant protection scheme, planned for 2011, will remove the potential for plant damage under unplanned contingency conditions at peak load.

3.5.1.52 HORSHAM TERMINAL–STAWELL ZONE SUBSTATION SUBTRANSMISSION LINE No.2 CIRCUIT (HOTS-STL #2) 66kV

Asset Description

The Horsham Terminal to Stawell Zone Substation No.2 circuit 66kV line comprises of 61.54 km of 66kV overhead conductor. The line is switched by a 66kV circuit breaker off the No.2 66kV bus at Horsham Terminal station. This line is in a loop network configuration with the HOTS-STL #1 66kV line, and for the loss of one line, the other will maintain supply to the customers. The loop supplies mainly the domestic, commercial and industrial areas of Stawell and Ararat.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: HOTS-STL #2 (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	23.7	23.9	24.2	24.5	24.7
Summer % Overload [See Note 1 Sec 3.5]	22.0	23.3	24.7	26.1	27.5
50th percentile Winter Maximum Demand (MVA)	17.5	17.7	17.8	18.0	18.2
Winter % Overload [See Note 1 Sec 3.5]	-	-	-	-	-
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	26	31	37	43	51
Annual hours at risk [See Note 3 Sec 3.5]	22	25	28	32	35

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by thermally uprating the HOTS-STL #2 line.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to thermally uprate the HOTS-STL #2 line. It is expected that this project will not occur within the above forecast period. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk. In addition, Challicum Hills Windfarm (CHW) alleviates this constraint when generating. It's maximum output is 52.5MW.

3.5.1.53 KERANG TERMINAL–SWAN HILL ZONE SUBSTATION SUBTRANSMISSION LINE No. 1 CIRCUIT (KGTS-SHL #1) 66kV

Asset Description

The Kerang Terminal Station to Swan Hill Zone Substation No 1 66kV line comprises of 65.9 km of 66kV overhead conductor. The line is part of a 66kV loop from the Kerang Terminal station providing firm supply to Swan Hill zone substation. This line is one of two lines supplying Swan Hill zone substation and for the loss of this line the other line will maintain supply to the customers. KGTS-SHL #1 supplies mainly the domestic, commercial and industrial areas of Swan Hill.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: KGTS-SHL #1 (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	51.6	53.4	55.2	57.5	60.4
Summer % Overload [See Note 1 Sec 3.5]	20.0	24.1	28.3	33.7	40.4
50th percentile Winter Maximum Demand (MVA)	29.7	30.8	31.6	32.5	33.7
Winter % Overload [See Note 1 Sec 3.5]	-	-	-	-	-
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	161	258	396	624	1008
Annual hours at risk [See Note 3 Sec 3.5]	59	84	116	162	230

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away/ emergency generation to alleviate loading on the line.
- Augment capacity by reconductoring the KGTS-SHL #1 line in stages.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to reconductor the KGTS-SHL #1 line in stages. It is expected that this project will not commence before 2015. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.54 KERANG TERMINAL–SWAN HILL ZONE SUBSTATION SUBTRANSMISSION LINE No. 2 CIRCUIT (KGTS-SHL #2) 66kV

Asset Description

The Kerang Terminal Station to Swan Hill Zone Substation No 2 66kV line comprises of 76.4 km of 66kV overhead conductor. The line is part of a 66kV loop from the Kerang Terminal station providing firm supply to Swan Hill zone substation. This line is one of two lines supplying Swan Hill zone substation and for the loss of this line the other line will maintain supply to the customers. KGTS-SHL #2 supplies mainly the domestic, commercial and industrial areas of Swan Hill.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: KGTS-SHL #2 (66kV)	**2012**	**2013**	**2014**	**2015**	**2016**
50th percentile Summer Maximum Demand (MVA)	46.0	47.6	49.4	51.1	53.3
Summer % Overload [See Note 1 Sec 3.5]	7.1	10.6	14.8	18.8	24.0
50th percentile Winter Maximum Demand (MVA)	27.5	28.4	29.0	29.9	30.6
Winter % Overload [See Note 1 Sec 3.5]	-	-	-	-	-
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	13.4	32.9	75.8	140.3	260.7
Annual hours at risk [See Note 3 Sec 3.5]	11	19	36	53	83

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away/ emergency generation to alleviate loading on the line.
- Augment capacity by reconductoring the KGTS-SHL #2 line.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to reconductor the KGTS-SHL #2 line. It is expected that this project will not occur before 2018. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.55 KEILOR TERMINAL STATION – MELTON ZONE SUBSTATION SUBTRANSMISSION LINE CIRCUIT (KTS-MLN) 66kV

Asset Description

The Keilor to Melton Zone Substation 66kV line comprises of 29km of 66kV overhead conductor. The line is switched by a circuit breaker from the 66kV bus at Keilor Terminal Station. The line is in a meshed network configuration with the KTS-SHM (Jemena), KTS-SBY (Jemena), SBY-SHM (Jemena) and SBY-WND and SBY-MLN lines. For the loss of either KTS-SHM or KTS-SBY line, the other lines will maintain supply to the customers. KTS-MLN supplies the Woodend, Gisborne, Melton and Rockbank areas.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: KTS-MLN (KTS-SHM OOS)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	99.9	102.2	105.8	109.2	112.5
Summer % Overload [See Note 1 Sec 3.5]	5.9	8.4	12.2	15.8	19.3
50th percentile Winter Maximum Demand (MVA)	84.6	86.6	90.5	92.4	97.5
Winter % Overload [See Note 1 Sec 3.5]	-	-	-	-	-
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	7.4	15.0	30.7	54.5	88.7
Annual hours at risk [See Note 3 Sec 3.5]	3.2	4.7	6.7	12.5	17.5

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by thermally augmenting the KTS-MLN line.
- Establish new Deer Park Terminal Station (DPTS) to transfer MLN and SU Zone Substation from the Keilor Terminal Station network as part of a Connection Asset augmentation plan to alleviate load at risk at Keilor Terminal Station (refer to 2011 Transmission Connection Asset Report) and convert part of the KTS-MLN and MLN-SBY lines to a new direct KTS-SBY No2 66kV line. Also required are new 66kV lines from MLN & SU to DPTS. This will reduce the load at risk on the KTS-SBY and KTS-SHM (both Jemena) 66kV lines as well as maintain adequate supply to WND Zone Substation.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to establish new DPTS, DPTS-MLN No.1 & No.2 and DPTS-SU No.1 & No.2 66kV lines and KTS-SBY No2 66kV line in 2016. This will mitigate risk on the supply to WND as well as Jemena's 66kV lines. The other alternatives do not solve the risk issues at Keilor Terminal Station as per the 2011 TCPR. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.56 MOOROOPNA ZONE SUBSTATION–SHEPPARTON ZONE SUBSTATION SUBTRANSMISSION LINE (MNA–STN) 66 kV

Asset Description

The Mooroopna Zone Substation to Shepparton Zone Substation 66 kV line comprises of 7.8 km of 66 kV overhead conductor. The line is part of a 66 kV loop from the Shepparton Terminal station providing firm supply to both Mooroopna and Shepparton zone substations. This line is in a 66 kV loop configuration and for the loss of this line the other lines will maintain supply to the customers. MNA–STN supplies the Mooroopna and Shepparton areas.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: MNA–STN (66 kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	52.5	53.3	54.1	54.9	55.7
Summer % Overload [See Note 1 Sec 3.5]	5.6	7.2	8.8	10.4	12.1
50th percentile Winter Maximum Demand (MVA)	34.3	34.6	34.8	35.1	35.3
Winter % Overload [See Note 1 Sec 3.5]	-	-	-	-	-
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	14	25	40	58	79
Annual hours at risk [See Note 3 Sec 3.5]	12	15	21	26	30

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by reconductoring the MNA-STN line.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to reconductor limiting sections of the MNA-STN line. It is expected that this project will not occur in the above forecast period. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.57 NUMURKAH ZONE SUBSTATION–COBRAM EAST ZONE SUBSTATION SUBTRANSMISSION LINE (NKA–CME) 66 kV

Asset Description

The Numurkah Zone Substation to Cobram East Zone Substation 66 kV line comprises of 33.2 km of 66 kV overhead conductor. The line is a radial 66 kV supply from the Numurkah Zone Substation to Cobram East Zone Substation. For the loss of this line, all customers on CME will lose supply. NKA–CME supplies the Cobram and Yarrawonga areas.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: NKA-CME (66 kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	42.1	42.8	43.4	44.1	44.9
Summer % Overload [See Note 1 Sec 3.5]	100	100	100	100	100
50th percentile Winter Maximum Demand (MVA)	32.9	33.0	33.2	33.3	33.5
Winter % Overload [See Note 1 Sec 3.5]	100	100	100	100	100
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	189692	191608	193750	195666	198089
Annual hours at risk [See Note 3 Sec 3.5]	8760	8760	8760	8760	8760

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by establishing NKA-CME #2 line to off-load NKA-CME #1.

Preferred network option(s) for alleviation of constraints

It is proposed that the next major augmentation will be to establish a new NKA-CME #2 line. It is expected that this project will not occur before 2016. In the interim, the load on the line will be monitored, and load transfers away to alternative supply points and emergency generation will be utilised, if necessary to mitigate load at risk.

3.5.1.58 SUNBURY ZONE SUBSTATION – WOODEND ZONE SUBSTATION SUBTRANSMISSION LINE NO. 1 CIRCUIT (SBY-WND #1) 66kV

Asset Description

The Sunbury to Woodend Zone Substation No.1 66kV line comprises of 42km of 66kV overhead conductor. The line is switched by a circuit breaker from the 66kV ring bus at Sunbury Zone Substation. The line is in a meshed network configuration with the KTS-SBY (Jemena) #1 & #2 lines, KTS-MLN line, MLN-SBY line, SBY-WND #1 and SBY-WND #2 66kV lines. For the loss of the SBY-WND #1 line the other lines will maintain supply to the customers. SBY-WND #1 supplies the Woodend and Gisborne areas.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: SBY-WND #1 (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	50.1	52.3	54.8	57.5	60.6
Summer % Overload [See Note 1 Sec 3.5]	21.5	27	33	39.5	47.2
50th percentile Winter Maximum Demand (MVA)	53.4	54.5	55.8	57.1	58.5
Winter % Overload [See Note 1 Sec 3.5]	0	0	0	0	0
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	105.2	202.6	381.4	701.7	1346.7
Annual hours at risk [See Note 3 Sec 3.5]	39.5	67.8	122.8	209.8	394

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by thermally uprating the SBY-WND #1 line.
- Augment capacity by reconductoring the under rated sections of the SBY-WND #1 line.

Preferred network option(s) for alleviation of constraints

Powercor has committed to the establishment of; a new zone substation, Gisborne (GSB) to be completed in 2012. This will mitigate risk on the SBY-WND #1 66kV line. It is proposed that the next major augmentation will be to reconductor the under rated sections of the SBY-WND #1 line. It is expected that this project will not occur before 2018. In the interim, the load on the line will be monitored, and load transfers away to alternative supply points to mitigate load at risk.

3.5.1.59 SUNBURY ZONE SUBSTATION – WOODEND ZONE SUBSTATION SUBTRANSMISSION LINE NO. 2 CIRCUIT (SBY-WND #2) 66kV

Asset Description

The Sunbury to Woodend Zone Substation No.2 66kV line comprises of 39km of 66kV overhead conductor. The line is switched by a circuit breaker from the 66kV ring bus at Sunbury Zone Substation. The line is in a meshed network configuration with the KTS-SBY (Jemena) #1 & #2 lines, KTS-MLN line, MLN-SBY line, SBY-WND #1 and SBY-WND #2 66kV lines. For the loss of the SBY-WND #2 line the other lines will maintain supply to the customers. SBY-WND #2 supplies the Woodend and Gisborne areas.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: SBY-WND #2 (66kV)	2012	2013	2014	2015	2016
50^{th} percentile Summer Maximum Demand (MVA)	52.1	54.8	58.1	61.3	66.6
Summer % Overload [See Note 1 Sec 3.5]	26.5	32.9	40.9	48.8	61.7
50^{th} percentile Winter Maximum Demand (MVA)	55.5	56.9	58.5	59.8	61.3
Winter % Overload [See Note 1 Sec 3.5]	34.8	38.2	42.0	45.1	48.9
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	3054	4258	6049	8017	11950
Annual hours at risk [See Note 3 Sec 3.5]	910	1154	1485	1864	2550

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by thermally uprating the SBY-WND #2 line.
- Establish new zone substation Gisborne (GSB) to off-load WND, and therefore the under rated section of the SBY-WND #2 line.

Preferred network option(s) for alleviation of constraints

Powercor has committed to the establishment of; a new zone substation, Gisborne (GSB). This will mitigate risk on the SBY-WND #2 66kV line. It is expected that this project will be completed in 2012. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

3.5.1.60 SHEPPARTON TERMINAL STATION – SHEPPARTON ZONE SUBSTATION SUBTRANSMISSION LINE (SHTS–STN) 66kV

Asset Description

The Shepparton Terminal Station to Shepparton Zone Substation 66 kV line comprises of 4.94 km of 66 kV overhead conductor. The line is part of a 66 kV loop from the Shepparton Terminal Station providing firm supply to Shepparton and Mooroopna zone substations. This line is in a 66 kV loop configuration and for the loss of this line the other lines will maintain supply to the customers. Switchgear at Shepparton zone substation limits the line rating, but will be replaced in early 2012. SHTS–STN supplies the Mooroopna and Shepparton areas.

Magnitude and impact of loss of load

The table below provides more detailed data on demand forecasts, 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:

Subtransmission Line: SHTS–STN (66kV)	2012	2013	2014	2015	2016
50th percentile Summer Maximum Demand (MVA)	99.3	100.6	101.9	103.1	104.5
Summer % Overload [See Note 1 Sec 3.5]	8.6	10.0	11.4	12.7	14.2
50th percentile Winter Maximum Demand (MVA)	63.2	63.7	64.2	64.6	65.1
Winter % Overload [See Note 1 Sec 3.5]	-	-	-	-	-
Annual energy at risk (MWh) [See Note 2 Sec 3.5]	59	84	115	147	188
Annual hours at risk [See Note 3 Sec 3.5]	18	23	27	30	35

Feasible options for alleviation of constraints

The following options are technically feasible and potentially economic to mitigate the risk of supply interruption and/or to alleviate the emerging constraint (See Notes 4 & 5, Section 3.5 for a description of options common to all subtransmission lines):

- Contingency plan to transfer load away to alleviate loading on the line.
- Augment capacity by replacing limiting switchgear at STN.

Preferred network option(s) for alleviation of constraints

Powercor has committed to replacing limiting switchgear at Shepparton zone substation. It is expected that this project will be completed in 2012. In the interim, load transfers away to alternative supply points will be utilised to mitigate load at risk.

Attachment 5 – Summary of Planned responses to Load at Risk

Zone Substation	Major Project Augmentations	2012 $m	2013 $m	2014 $m	2015 $m	2016 $m
BGO	Install 2 x 22kV feeder at Bendigo Terminal Station and transfer load. This will also mitigate risk on BETS-EHK & BGO-EHK.		2.6			
BMH	Augment BMH & MLN 22kV network to increase load transfer away capacity to adjacent Zone substation		0.8			
CME	CME transfers to Essential Energy				1.7	
CHA	Replace transformer disconnect switches					0.1
CLC	Augment existing transformer	5.97				
CTN	Installation of additional transformer	1.2				
DDL	Installation of additional transformer				5.6	
EHK	Installation of additional transformer				6.0	
GCY	Install plant protection scheme		0.14			
GLE	Upgrade two transformers		0.6	8.0		
LV	Upgrade one transformer			3.0		
LVN	Install two capacitor banks	1.3				
MBN	Install 22kV feeder tie to MDA. This will also mitigate risk at MDA.			0.5		
MDA	Install Plant Protection Scheme		0.2			
MLN	Installation of additional transformer			0.3	3.2	
MRO	Installation of additional transformer					4.0
SA	Augment feeder ties between SA and SSE to balance loads between transformer groups at Keilor Terminal Station	0.5				
SHP	Installation of additional transformer	2.5				
SSE	Installation of additional transformer in 2012 and 2x 12MVAr Capacitor banks in 2015	3.0			1.2	
STN	Installation of additional transformer	2.5				
SU	Establish new zone substation, Truganina TNA to offload SU, LV, LVN & WBE				1.2	12.8
WND	Establish Gisborne (GSB) Zone Substation and transfer load. This will also mitigate risk on SBY-WND #2.	11.7				
WPD	Install plant protection scheme		0.14			

<table>
<tr><th><u>Subtransmission Line</u></th><th><u>Major Project Augmentations</u></th><th><u>2012</u>
$m</th><th><u>2013</u>
$m</th><th><u>2014</u>
$m</th><th><u>2015</u>
$m</th><th><u>2016</u>
$m</th></tr>
<tr><td>BATS-BMH</td><td>Works to increase thermal rating of line (uprate)</td><td>0.1</td><td></td><td></td><td></td><td></td></tr>
<tr><td>BLTS-BMH</td><td>Reconductor line to increase capacity</td><td></td><td>2.4</td><td>3.8</td><td>1.4</td><td></td></tr>
<tr><td>BETS-CTN</td><td>Reconductor line to increase capacity</td><td colspan="5">15.1</td></tr>
<tr><td>CLC-CDN</td><td>Works to increase thermal rating of line (uprate)</td><td></td><td></td><td>1.9</td><td></td><td></td></tr>
<tr><td>DPTS-MLN #1 & #2</td><td>Establish two new 66kV lines from DPTS to MLN</td><td></td><td></td><td>1.0</td><td>8.3</td><td>8.3</td></tr>
<tr><td>DPTS-SU #1 & #2</td><td>Establish two new 66kV lines from DPTS to SU</td><td></td><td></td><td></td><td>1.0</td><td>8.4</td></tr>
<tr><td>DPTS-TNA #1 & #2</td><td>Establish two new 66kV lines from DPTS to TNA</td><td></td><td></td><td></td><td>0.5</td><td>4.3</td></tr>
<tr><td>GLE-DDL #1</td><td>Reconductor line to increase capacity</td><td colspan="2">0.9</td><td></td><td></td><td></td></tr>
<tr><td>GLE-DDL #2</td><td>Reconductor line to increase capacity</td><td>1.3</td><td></td><td></td><td></td><td></td></tr>
<tr><td>GTS-GB</td><td>Reconductor line to increase capacity</td><td colspan="2">0.25</td><td></td><td></td><td></td></tr>
<tr><td>GTS-GLE #1</td><td>Reconductor line to increase capacity</td><td colspan="2">2.8</td><td></td><td></td><td></td></tr>
<tr><td>GTS-GLE #2</td><td>Reconductor line to increase capacity</td><td>2.7</td><td></td><td></td><td></td><td></td></tr>
<tr><td>KGTS-SHL #1</td><td>Reconductor line to increase capacity</td><td></td><td></td><td></td><td>0.1</td><td>4.0</td></tr>
<tr><td>KTS-SBY #2</td><td>New line from former KTS-MLN & SBY-MLN as part of the creation of new DPTS and 66kV lines from MLN to DPTS</td><td></td><td></td><td></td><td>0.5</td><td>5.7</td></tr>
<tr><td>NKA-CME</td><td>Establish NKA-CME #2 line</td><td></td><td></td><td></td><td colspan="2">11.0</td></tr>
</table>

Attachment 6 – Glossary of Terms

ATS	Altona Terminal Station
BATS	Ballarat Terminal Station
BETS	Bendigo Terminal Station
BLTS	Brooklyn Terminal Station
EGTS	East Geelong Terminal Station(Future)
FBTS	Fishermen's Bend Terminal Station
GTS	Geelong Terminal Station
HOTS	Horsham Terminal Station
KGTS	Kerang Terminal Station
KTS	Keilor Terminal Station
RCTS	Red Cliffs Terminal Station
SHTS	Shepparton Terminal Station
TGTS	Terang Terminal Station
kW	Kilo Watt
kWh	Kilo Watt Hour
kVA	Kilo Volt Ampere
kVAr	Kilo Volt Ampere Reactive
km	Kilometer
MW	Mega Watt
MWh	Mega Watt Hour
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive